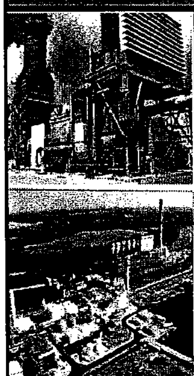
ATTACHMENT A

REFERENCE MATERIALS



EPA's Perspective on

Cleaner Coal

Presentation for

20th Symposium on Western Fuels

by

Robert J. Wayland, Ph.D.

U.S. Environmental Protection Agency

Office of Air and Radiation

October 24, 2006

Cleaner Coal: EPA Has Focused on Existing Coal-fired Generation Units

- EPA finalized the Clean Air Interstate, Mercury, and Visibility Rules in 2005
- The annual costs to the power industry of these rules will be substantial:
  - 2010: $ 2.7 billion
  - 2015: $ 4.4 billion
  - 2020: $ 6.1 billion
- The health benefits are much larger. EPA estimates that by 2020 the annual health benefits are between $ 120 to 143 billion – and there are more visibility and environmental benefits that EPA has not estimated.
- Actions to comply begin broadly in the Fall 2006.
  - Expect large capital investments in pollution control.
  - Largest cost impacts will be in the East.
- The rules provide extensive air emissions reductions while the public still has affordable, reliable electricity from a diverse generation mix.
- The rules help States comply with the National Ambient Air Quality Standards for ozone and fine particles and the Regional Haze Program.
- The rules improve air quality while creating headroom for growth.

EPA's Actions to Date – A Progress Report

- **Regulatory Issues**
  - **Current issue for IGCC facilities is New Source Review (NSR) and Prevention of Significant Deterioration (PSD) permitting**
    - **December 13, 2005 – EPA memo (IGCC and BACT)**
      - **EPA's interpretation of when IGCC should be considered in NSR and PSD permitting**
      - **In the case of pulverized coal boilers and similar conventional coal-fired technologies, IGCC should not be considered as control technology candidate under BACT**
  - **Selective Catalytic Reduction (SCR) as BACT for IGCC units**

- **Headquarters and Regional offices want to work with companies interested in developing IGCC technology in the near future**

- **EPA is committed to working with State permitting authorities**
  - **States are the primary permitting authority under NSR/PSD – often can be more stringent than Federal regulations**
  - **Agency is attempting to be "upfront" and let States know "where we stand" on IGCC permitting issues**
    - **Anticipate this may help expedite and streamline the NSR & PSD permitting process considerably**

- **Joint EPA/DOE study on environmental and cost aspects for an IGCC unit versus a conventional coal plant**
    - **Final Report:** *"Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle (IGCC) and Pulverized Coal Technologies"*, **EPA-430/R-06/006**, July 2006

Regulatory Incentives

- **Existing controls through CAIR, CAMR, and CAVR generally make building new cleaner units more attractive – retrofitting the fleet has substantial costs**

- **Also are incentive in the controls for new units:**
  - **Final New Source Performance Standards (NSPS) for Subpart Da**
    - **IGCC Units constructed on/after February 9, 2005 would be subject to the same emission limits as a coal-fired boiler**
    - **Given current IGCC technology, this should not pose any regulatory burden on new, planned IGCC facilities**
  - **Final Clean Air Mercury Rule (CAMR)**
    - **Created separate source category for IGCC units**
      - **Hg emission limit of 20×10^{-6} lb/MWh**
      - **Comparable to a bituminous PC-fired power generation system**

EPA's Future Plans and Needs

- EPA is working on models to assess the economic viability of IGCC plants under different conditions
  - Working closely with DOE on these economic and environmental efforts
- One existing barrier today is the cost of IGCC technology
  - EPA is working in conjunction with DOE to evaluate various proposals to address this economic barrier
  - Energy Policy Act of 2005
    - Exploring options and incentives such as loan guarantees and tax credits
- EPA is expanding its interest to include both IGCC and other types of coal-to-liquids/co-production projects

EPA is not trying to pick a technology winner, but trying to ensure that IGCC has a chance to prove itself commercially

For general and regulatory information:

Dr. Robert J. Wayland
Office of Air Quality Planning & Standards
Research Triangle Park, NC
(919) 541-1045

On technical details, air emissions and other environmental aspects of IGCC:

Dr. Sikander Khan
Office of Atmospheric Programs
Washington, DC
(202)343-9781

WorleyParsons

resources & energy

WorleyParsons Report No. EJ-2006-01
Nevada Power Purchase Order 0001012232
WorleyParsons Job No. 53774010

20-Jun-06 17:03 Revision B

Nevada Power IGCC Market Status and Feasibility Study
Performance and Estimate Report

June 2006

Prepared for:

Nevada Power.

Sierra Pacific
RESOURCES

Prepared by:
WorleyParsons Group, Inc.
2675 Morgantown Road
Reading, Pennsylvania 19607-9676 USA

when experience counts

TABLE OF CONTENTS

P:\Contracts_NevadaPower\Report\20 June NEVADA POWER -Perf Rept 1 - Rev B.doc

LIST OF EXHIBITS

Revision Record

Revision	Date	Content
A	28 Apr 06	Draft - Initial Issue to client for review
B	20 June 06	Incorporate Client Comments

Notice

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by WorleyParsons.

Due to the limited timeframe available, it was not possible to obtain project-specific information from the gasifier licensors. Therefore, WorleyParsons in-house models and data were utilized to predict the gasifier syngas yields and technical limitations. This in-house modeling, although we believe to be representative of the selected configurations, will likely vary from the official vendor information, design standards and conservatisms (margins).

Although, the basis of this work reflects the best technical and cost inputs that where available at the time the work was performed, WorleyParsons does not take direct responsibility for decisions which are based on the conceptual results presented in this study.

TERMINOLOGY

AGR	acid gas removal
ASU	air separation unit
BEC	Bare erected cost
Btu	British thermal unit
ºC	degrees Celsius
CC	combined cycle
CO	carbon monoxide
CO_2	carbon dioxide
COE	cost of electricity
COS	Carbonyl sulfide
CT	combustion turbine
DOE	Department of Energy (United States)
EAF	equivalent availability factor
ºF	degrees Fahrenheit
fps	feet per second
FW	Foster Wheeler
GADS	Generating Availability Data System
GE	General Electric
GT	gas turbine
Hg	mercury
HHV	Higher Heating Value
HRSG	hear recovery steam generator
IDC	Interest during construction
IGCC	Integrated Gasification Combined Cycle
kW, kWe	kilowatt electric
kWt	kilowatt thermal
MDEA	methyl diethanolamine
MMBtu	million Btu
MSL	mean sea level
MW, MWe	megawatt electrical
MW_t	megawatt thermal
NERC	North American Electric Reliability Council
NG	natural gas
NOx	nitrous oxides
O_2	oxygen
OEM	original equipment manufacturer
O&M	Operating and Maintenance
Part.	Particulate emissions
PC, pc	pulverized coal
PE&C	Parsons Energy & Chemicals, part of the WorleyParsons Group
PM	particulate material
ppm	parts per million
PRB	Power River Basin (coal)
psia	lb/square inch (14.696 psi = 1 atm)
S	sulfur content of fuel
scf	standard cubic feet
scfd	standard cubic feet per day
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SRU	sulfur recovery unit
STG	steam turbine generator
Syngas	Synthetic gas
t	short ton (2,000 lbs)
TBtu	tera Btu, or 10^{12} Btu
TG	turbo-generator, (turbine-generator)
TGTU	tail gas treatment unit
t/h	ton/hour
ton	short ton, (2000 lbs)
t/h, tph	ton per hour
t/y, tpy	ton per year
TPC	Total plant cost
US, U.S.	United States
USD, US$	the United States Dollar
USDOE	United States Department of Energy
VOC	volatile organic compound
y, yr	year

Executive Summary

Nevada Power and Sierra Pacific requested a technology evaluation to include the design characteristics, cost, emissions and various tradeoffs of installing a nominal 600 MW coal-based power plant at several sites in Nevada, including Reid Gardner, Valmy. The work consisted of evaluating two different power generation technology options, namely the Integrated Gasification Combined Cycle (IGCC) and the Pulverized Coal (PC). The PC technology was evaluated for the Reid Gardner and Valmy site. The IGCC technology was also evaluated for the Reid Gardner, Valmy and the Ely site.

WorleyParsons prepared this technology evaluation for Nevada Power/Sierra Pacific by performing the following tasks, which are summarized in three documents.

a) Design Basis

b) Performance and Cost Estimates

c) IGCC Technology Review

Design Basis

The design basis was established with cooperation between WorleyParsons and Nevada Power / Sierra Pacific. The design basis consists of site parameters, ambient conditions, design fuel, cooling system configuration and major power plant design assumptions. These design assumptions include the selection of the PC technologies and the IGCC gasification and gas turbine technologies.

Key design goals and assumptions were decided during the kickoff discussions. The IGCC configuration was based on the Conoco-Phillips (E Gas) gasifier and the upgraded General Electric – 7FB gas turbine.

The design basis coal for this study is a Power River Basin blend from the Black Butte Coal Company.

Technology Description and Performance

Both the PC and the IGCC plant performance were modeled using WorleyParsons' in-house models and data. The overall plant performance for the two generation options is summarized in the following table

Exhibit ES-1
Estimated Plant Performance Summary

Parameter	Units	IGCC – E-Gas			Pulverized Coal	
		Reid Gardner	Valmy	Ely	Reid Gardner	Valmy
Elevation	ft	1,700	4,500	6,100	1,700	4,500
Design Ambient Temperature	°F	68	50	45	68	45
Design Ambient Relative Humidity	%	50	50	50	50	50
Net Capacity[2].	MW	569	541	515	600	600
TPC Capital Cost[1]	$/kW	1,803	1,933	N/A	1,578	1,459
Heat Rate, (HHV) [2]	Btu/kWh	8,700	8,585	8,570	8,941	8,750
Fixed O&M	$/kW	37.92	39.39	N/A	36.00	32.67
Variable O&M	$/MWh	5.09	5.57	N/A	3.33	3.09
SO_2 @ 15% O_2 [3]	lb/MMBtu (HHV)	0.0064	0.013	0.013	0.06	0.2
NOx @ 15% O_2 [3]	lb/MMBtu (HHV)	0.013	0.056	0.056	0.07	0.15
CO @ 15% O_2 [3]	lb/MMBtu (HHV)	0.057	0.057	0.057	0.10	0.15
PM [3]	lb/MMBtu (HHV)	0.0145	0.0145	0.0145	0.012	0.015
Water Use	ac-ft/yr	2,640	2,210	2,100	4,030	3,520

Notes: Relevant notes and details for the above values are presented in the body of the report.

1. TPC Capital Costs have an accuracy range of ± 30% and are indicative of the “overnight construction” cost. Values exclude costs for Owner’s financing costs, EPC Contractor risk, and escalation during construction.
2. The performance values are based on predicted performance that is subject to OEM verification. The values are base load net plant heat rates for syngas or PC operation with hybrid cooling system (50% dry & 50% wet) configuration.
3. Emissions for the Reid Gardner site are based on LAER requirements (Non-attainment area). Emissions for the Valmy and Ely sites are based on BACT requirements.

WorleyParsons estimated the annual emissions based on 7,450 hours/year operation (85% capacity factor) for both technologies. The estimated emissions results are summarized below.

Exhibit ES-2
Estimated Air Emissions Summary

	IGCC –E-Gas			Pulverized Coal	
Pollutant	**Reid Gardner**	**Valmy**	**Ely**	**Reid Gardner**	**Valmy**
SO_2 (2)	120	225	215	1200	3914
NOx	240	960	920	1400	2936
CO	1050	980	930	2000	2936
Particulate	270	250	245	240	294

Notes:

(1) Emissions for the Reid Gardner site are based on LAER requirements (Non-attainment area). Emissions for the Valmy and Ely sites are based on BACT requirements.

(2) IGCC emissions do not include SO_2 from SRU / TGTU (Tailgas Treatment Unit) which is estimated to be less than 15 tons/year.

Due to the limited scope of this evaluation, project-specific information from the gasifier licensors, the gas turbine vendor, and the PC boiler vendor was not obtained. Therefore, WorleyParsons used in-house models and data, as well as data from the public domain to predict the performance and technical limitations. This in-house modeling/data has been calibrated to past vendor data and is believed to be representative of the selected configurations, but will likely vary when official vendor information is obtained.

IGCC Technology Review

A study of the status of various IGCC Technologies is contained in Appendix E. The results of the study are summarized below:

The history of operation of gasifiers and IGCC systems, irrespective of the design and licensor, has shown that each unit had some problems, and generally the projects were not initially successful. However, it is noted that over the years, the sources of the major problems were identified, and engineering solutions found. Therefore, it can be logically expected that future units will likely experience fewer overall problems, especially where experience exists for similar fuels. Although the reliability has improved, long term operation of existing IGCC facilities will be required to demonstrate performance, availability and reliability levels that are expected of a mature PC unit.

For the next generation of IGCC plants, the cost, performance, availability and reliability of the units with the improvements planned by the IGCC licensors remains yet to be demonstrated. As more IGCC plants come on line, all these data will become publicly available to determine long-term values for comparison to that of a PC unit.

Due to the complexity of coal gasification process by itself and due to the integration requirements with the power block in IGCC configuration, it is expected that some problems will still exist for the future plants that need to be resolved. This is not uncommon in the industry as the experience shows that even the coal-fired boilers experience problems that are unique to a design and coal combination, but problems are generally solvable. IGCC's gasification/AGR/power block integration complexity results in more opportunity for start-up problems and unplanned outages. It is expected that initial operating periods for an IGCC will incur lower availability than conventional PC.

IGCC Licensors have stated that they expect IGCC power plants to be 20 - 25 % more expensive than an equivalent PC plant. In addition, an IGCC plant will have more cost uncertainty than a Pulverized Coal plant due to the limited actual cost data in the industry.

Also, because of the effects of elevation on Gas Turbine output, the cost per kW of an IGCC plant will be higher at a higher elevation. (See Appendix E for details)

Advances in syngas cleanup systems, including experience with mercury removal suggests a promising future for the IGCC technology, as environmental restrictions become tighter. Also, developments in the gas turbine technology, including improved performance and emissions reduction techniques, better integration with ASUs, and other advancements, are projected to lower the overall IGCC plant heat rate, and unit costs. However, these projections along with the success of the new gas turbine and ASU integration concepts are yet to be proven in actual installation.

In summary, IGCC is an emerging technology which has some potential advantages with respect to Pulverized Coal, especially in emissions and efficiency. However, the costs, performance, availability, reliability and maintainability of the new generation of IGCC systems are yet to be demonstrated.

Other Options

Two other options that can be considered include

1. Centralized coal gasification based SNG production plant

   Another alternate would be to build a central gasification plant to produce synthetic natural gas (SNG) to feed existing or new Combined Cycle (CC) plants in the area. This SNG plant would include an ASU plant, Gasifier, Shift Converter, Sulfur removal system, and Methanation system to produce pipeline quality SNG. Although this configuration would require less integration with the CC plant as typically seen in a conventional IGCC plant, the overall plant design would be much more intricate. The SNG plant may require separate steam turbine(s), auxiliary boiler(s) and gas compression system to support the SNG production and delivery depending on the selected gasifier technology.

   A DOE study under way gives data on the cost and performance of producing SNG to be used in a conventional dedicated CC plant with entrained flow gasifier technology.[1] This study estimates the efficiency of converting coal to electricity using this approach to be in the range of 5 - 10 percentage points lower than a conventional IGCC plant. This lower thermal efficiency is attributable to the lack of integration between the gasification island and the power island, along with unrecoverable losses associated with the SNG process.

   It is not normal to compare the cost of a centralized gasification plant to an IGCC plant because of the difficulties to compare them on a level playing field. However, if an SNG plant was dedicated to support an existing combined cycle plant the capital cost on a $ / kWe basis (excluding the capital cost of the existing CC plant) would be on the order of 20 - 40 percent more than the cost of an IGCC plant of similar size[2].

   The major issues related to a centralized SNG plant versus an IGCC plant are summarized below:

   - No integration required with the combined cycle plant.

- The SNG production plant availability and operation is independent of the combined cycle plant operation and electricity dispatch requirements, unlike the IGCC plant.
- Combined cycle plants can use Dry Low NOx combustors that have the potential of lower NOx emissions.
- Typically lower SOx emissions due to much higher level of sulfur removal requirements to make pipeline quality SNG.
- Overall plant heat rate (fuel HHV divided by the equivalent KW) is poorer than a conventional IGCC plant.
- When the price of natural gas is relatively high, the SNG plant can become economically attractive. The variable O&M cost (excluding fuel cost) is about $2 – 2.5/MMBtu –HHV. The levelized cost of SNG production can be expected to be in the range of $7 - $9/MMBtu-HHV (excluding fuel cost) depending on the economic factors. [3]

2. Reuse the Piñon Pine Gasification Plant

The Piñon Pine gasification project did not successfully operate in a commercial fashion, due to numerous start-up issues. The plant has been plagued by technical, construction and contract problems and has never been fully operational. A detailed evaluation of the Pinion Pine gasification plant was outside the scope of this study. However, the details of the issues are contained in the DOE Report. [4]

It is also to be noted that much of the gasification technology built into Piñon Pine is outdated and is different from the gasification technologies presently being proposed by the OEMs for future IGCC applications. The Pinion Pine is also a much smaller unit (about 100 MW net) rather than the 550 - 600 MW IGCC units which are being considered at this time.

1 Introduction

1.1 Scope

Nevada Power and Sierra Pacific requested that several key issues be addressed in the study. These key issues included the primary PUC drivers, the fuel basis for the analyses, emission targets required for permitting, and an analysis of the competitive coal-based technologies. The fuel feedstock currently available to Nevada Power and Sierra Pacific at their existing coal plants was taken into consideration. Nevada Power and Sierra Pacific had power generation targets of 600 MW at each site. Plant operating profiles and emissions goals were also important issues. And, as with any new generation facility, water supply and waste water discharge quantities were limited. The design basis document summarizes this information. The locations considered for IGCC technology include the Reed Gardner plant in the south, the Valmy plant in the north, The locations considered for the PC technology include the Reed Gardner plant location in the south and the Valmy plant in the north. Performance for the IGCC technology is included for the Ely location in the north

The technology evaluation included comparisons of performance and costs for new coal fired generation at the different site locations. Performance of the units was modeled taking into account site characteristics such as the type of fuel available, the amount of water available, the site altitude, and the ambient conditions. One gasifier technology (E- Gas) was selected, which set the IGCC cycle configuration. The performance was estimated for both the IGCC and PC cases necessary to produce a net plant output of 500 - 600 MW.

The results of the heat balance models for both the PC and the IGCC configurations were then integrated with the cost estimating effort.

A water balance was performed for each technology at each of the respective sites to determine water consumption and waste water quantities. The HRSG stack emissions were calculated based on the constituents in the syngas and the predicted performance of the General Electric 7FB gas turbines.

Conceptual level capital cost estimates were generated. Conceptual level O&M costs were estimated.

The result of this effort are contained in the Performance and Estimate Report

WorleyParsons drafted a report to compare IGCC technologies. The report is contained herein as Appendix E and summarizes the following:

a) A brief overview of the history of solid fuel gasification and IGCC, the relatively recent developments in the technology, and future development plans and programs, including a description of the current government funded programs in clean coal technology.

b) A description and brief review of each of the commercial gasification technologies: The overview includes the status of each technology with regards to current commercial operation, the applicability of each technology for the fuels available, and the typical performance of each technology for syngas production.

c) Power plant design issues were analyzed, including gas turbine options and design issues with regard to the use of syngas, heat recovery steam generator (HRSG) issues, especially with regard to the potential for supplemental firing; and steam turbine issues.

d) An analysis of the key issues was performed with regard to the use of IGCC as a commercial technology. The analysis included the pros and cons of such issues as emissions, sulfur removal, mercury removal, and CO_2 sequestration. The analysis will also address economic issues, maintenance issues, and the production and handling of by-products. It is understood that Nevada Power and Sierra Pacific are electric generating companies; however, with IGCC technology, the by-products produced are significant and should be addressed commercially as a potential revenue stream.

2 Design Basis

This section summarizes the design concepts/parameters that form the basis for the analysis. The design basis includes site specific conditions, fuel analysis, and major power plant design goals and assumptions. The complete design basis document is contained in Appendix D.

2.1 Site Conditions

Site ambient conditions are required for the purpose of estimating performance of the power plant configurations and to size the equipment so that accurate performance and cost estimates can be made. The Ely site was added later in the study and is included for the IGCC configuration only. Note that because of the timing, Ely is not included in the design basis document in Appendix D.

The site conditions are summarized as follows:

Exhibit 2-1
Site Conditions

Site Characteristic	Units	Reid Gardner	Valmy	Ely
Site Elevation above Mean Sea Level	ft	1,700	4,500	6,100
Average Atmospheric Pressure	psia	13.82	12.46	11.73
Design Point (Annual Average) Temperature – dry bulb	°F	68	50	45
Design Point (Annual Average) Coincident Relative Humidity	%	50	50	50

2.2 Design Fuel

The design coal used as the basis for this study is a Power River Basin blend from the Black Butte Coal Company. The coal analysis was based on a 40/60 blend from their coal pits 8 and 10, respectively. The coal analysis is presented as follows:

Exhibit 2-2
Design Coal

Black Butte	Pit No. 8 Average	Pit No. 10 Average	Blend P8 (40%) & P10 (60%)
Proximate Analysis (AR)			
Moisture %	19.08	21.79	20.71
Ash %	7.38	6.79	7.03
Volatile %	29.95	29.44	29.64
Fixed Carbon %	43.97	42.06	42.82
HHV BTU/lb	9,800	9,350	9,530
Sulfur %	0.57	0.39	0.46
Ultimate Analysis			
Carbon %	57.84	53.15	55.03
Hydrogen %	3.88	3.62	3.72
Nitrogen %	1.43	1.05	1.20
Oxygen %	10.78	12.85	12.02
Chlorine %	0.02	0.01	0.01
Mineral Analysis of Ash			
SiO_2	52.33	50.34	51.14
Al_2O_3	24.67	12.19	17.18
TiO_3	1.07	0.80	0.91
Fe_2O_3	4.67	6.12	5.54
CaO	6.50	10.94	9.16
MgO	2.42	2.91	2.71
K_2O	0.54	0.58	0.56
Na_2O	0.86	4.69	3.16
SO_3	3.13	-	1.25
P_2O_5	1.83	-	0.73
Reducing Ash Fusion Temperature			
Initial Deformation	2,397	1,995	2,156
Soft Temp. (H=W)	2,455	2,118	2,253
Hemis. Temp. (H=$^1/_2$W)	2,501	2,151	2,291
Fluid Temp.	2,569	2,247	2,376
Sulfur Forms			
Pyritic Sulfur %	0.11	0.19	0.16
Sulfate Sulfur %	0.01	0.01	0.01

Black Butte	Pit No. 8 Average	Pit No. 10 Average	Blend P8 (40%) & P10 (60%)
Organic Sulfur %	0.39	0.25	0.31
EQ Moisture %	17.00	21.40	19.64
Hardgrove Grindability	47.14	48.74	48.10
Calculated Values			
Base to Acid Ratio	0.19	0.40	0.32
Silica Value	79.39	71.60	74.72
Dolomite %	59.45	54.87	56.70
Ash Precipitation Index	17.40	5.38	10.19
$SiO_2 : Al_2O_3$	2.12	4.13	3.33
lbs SO_2 / MBtu	1.15	0.83	0.96
$SiO_2 : CaO$	8.05	4.60	5.98

2.3 Design Sorbent

Limestone was used as a design sorbent for this study. The limestone analysis is presented below:

Exhibit 2-3
Design Sorbent

Delivery		By Train
		Analysis, %
Calcium Carbonate	$CaCO_3$	90%
Magnesium Carbonate	$MgCO_3$	5%
Silica	SiO_2	1%
Aluminum Oxide	Al_2O_3	1%
Iron Oxide	Fe_2O_3	1%
Sodium Oxide	Na_2O	1%
Potassium Oxide	K_2O	1%
Balance		0%
	Total	**100**

2.4 Environmental Requirements

The NSR process requires installation of emission control technology meeting either Best Available Control Technology (BACT) determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county. Nevada counties currently designated by the U.S. EPA as non-attainment areas are presented in Exhibit 2-4. [5]

Exhibit 2-4
Non-Attainment Areas in Nevada

County	Pollutant	Area Name	Classification
Clark	Carbon Monoxide	Las Vegas, NV	Serious
	8-hr Ozone	Las Vegas, NV	Subpart 1
	PM-10	Clark Co, NV	Serious
Washoe	Carbon Monoxide	Reno, NV	Moderate, ≤12.7 ppm
	PM-10	Washoe Co, NV	Serious

The Reid Gardner site is located in Clark County and the Valmy site is located in Humboldt County. Thus, for this study, the new unit at the Reid Gardner site was designed to meet LAER regulations (Exhibit 2-5), and the new units at the Valmy and Ely sites was designed to meet BACT regulations (Exhibit 2-6)

Exhibit 2-5
Presumptive LAER Emission Values

Process	Pollutants	Emissions Limitation	Type of Control Technology
PC Boiler	PM/PM-10	0.012 lb/10^6 Btu (HHV)	Fabric Filter or ESP
	Sulfur Dioxide	0.06 lb/10^6 Btu (HHV)	Low-Sulfur Fuel, FGD
	Nitrogen Oxides	0.07 lb/10^6 Btu (HHV)	SCR
	Carbon Monoxide	0.10 lb/10^6 Btu (HHV)	Combustion Controls
IGCC	PM/PM-10	0.0145 lb/10^6 Btu (HHV)	Syngas candle filter, water scrubber
	Sulfur Dioxide	0.0064 lb/10^6 Btu(HHV)	AGR
	Nitrogen Oxides	3.5 ppmvd @15% O_2	Nitrogen or steam diluent injection, Combustion controls, SCR
	Carbon Monoxide	25 ppmvd @15% O_2	Combustion Controls

Exhibit 2-6
Presumptive BACT Emission Values

Process	Pollutants	Emissions Limitation	Type of Control Technology
PC Boiler	PM/PM-10	0.015 lb/10^6 Btu (HHV)	Fabric Filter or ESP
	Sulfur Dioxide	0.2 lb/10^6 Btu (HHV)	Low-Sulfur Fuel, FGD
	Nitrogen Oxides	0.15 lb/10^6 Btu (HHV)	SCR
	Carbon Monoxide	0.15 lb/10^6 Btu (HHV)	Combustion Controls
IGCC	PM/PM-10	0.0145 lb/10^6 Btu (HHV)	Syngas candle filter, water scrubber
	Sulfur Dioxide	0.0128 lb/10^6 Btu (HHV)	AGR
	Nitrogen Oxides	15 ppmvd @15% O_2	Nitrogen or steam diluent injection, Combustion controls
	Carbon Monoxide	25 ppmvd @15% O_2	Combustion Controls

2.5 Major Design Goals and Assumptions

The key design goals and assumptions for the study, as decided at the kickoff meeting are presented below.

1. Target Net IGCC Plant Output: Approximately 500 - 600 MW, based on a nominal 2x1 plant.
2. Plant Operating Profile: Base Load
3. Water Supply Basis: Water availability is limited.
4. Cooling Configuration: Combined hybrid wet and dry cooling.
5. Waste water discharge: Zero discharge.
6. Natural Gas Supply: Available at the Reid Gardner Site.
7. Fuel Oil Storage: Storage for 3 days start up included for the Valmy site.
8. Ash Disposition: Ash can be sent to an on-site landfill.

2.6 Gasification / Gas Turbine Design Basis

During the project kickoff meeting, the status of potential gas turbine candidates for the IGCC application were reviewed. GE's upgraded 7FB gas turbines have been considered for the IGCC application. The changes anticipated from the earlier 7FA gas turbine model include a new first stage nozzle for higher firing temperatures and a new hot gas path design. General Electric expects to offer the 7FB gas turbine commercially for syngas application with delivery in 2007. The GE 7FB gas turbine was selected based on GE's intent to offer it in their standard IGCC design and on the fact that they have more experience in operating the F class gas turbine on syngas when compared to any other gas turbine supplier

A review of gas turbine design issues for operation firing syngas is presented below:

- The control firing temperature is reduced from that of natural gas operation to mitigate the adverse effect on the component life due to the higher flame temperature of hydrogen in the syngas. For the 7FA, GE reduced the firing temperature compared with natural gas firing by about 120°F. Similar temperature reduction is expected on 7FB units.
- Dry Low NO_X (DLN) combustors cannot be used due to the high flame speed produced by burning hydrogen and the possible flash back problems this may cause. General Electric uses diffusion type combustors (Multi Nozzle Quite Combustor or MNQC) for syngas application.
- A diluent is injected at the head end of the combustor to control the formation of NO_X by controlling the flame temperature. Typical diluents include steam, Nitrogen, and CO_2. The diluent increases the mass flow rate significantly through the back end of the gas turbine and increases the output. Nitrogen (N_2) is commonly used as diluent for NO_X control and power augmentation where Air Separation Units (ASU) are used.

- Emissions: Without diluent injection, NO_X levels are expected to be above 120 ppmvd. With diluent injection, NO_X levels can be reduced to 15 - 25 ppmvd. CO emission is typical about 25 ppmvd for the GE 7FA and is expected to be about the same for the 7FB gas turbine.

- Gas turbine output can be maintained fairly constant over a wide range of ambient temperatures. For GE 7FB gas turbines, the output is reduced at ambient temperatures above about 70°F due to turbine limitations such as high compressor temperature .

- The performance impact with altitude change (i.e., about 3 - 4% less output for each 1000 ft higher elevation) is very similar to natural gas operation.

- Gas turbines require a start up fuel (natural gas or distillate), which might also be used for full back up or for co-firing.

- Gas turbine performance degradation when firing syngas is expected to be similar to natural gas operation.

- General Electric gas turbines firing syngas will require combustion inspection at about 8,000 hours compared to about 12,000 hours for “F” class machines using natural gas as fuel.

- Specific design conditions and limits were not available for the GE 7FB (except as noted above), as GE was still in the process of developing them. WorleyParsons utilized informal information from GE and past in-house experience wherever possible. Should updated gas turbine information become available from GE, it is suggested that the performance and costs be reviewed and potentially updated.

2.7 Supercritical Pulverized Coal Unit Technology Basis

For the more mature supercritical PC technology, WorleyParsons used in-house data to predict performance for the technologies. The schematics are typical for each type of unit and are not intended to show any specific technology or manufacturer. The major U.S. domestic suppliers in the PC boiler market are: Foster Wheeler, Alstom Power and Babcock and Wilcox. All three have produced larger units, some operating on PRB coal. For the PC technology there are 4-7 foreign manufacturers as well.

3 Technology Description and Performance

3.1 Integrated Gasification Combine Cycle (IGCC)

The IGCC plant performance was developed using WorleyParsons in-house models and data. Due to the limited timeframe available, it was not possible to obtain project-specific information from the gasifier licensors. This in-house modeling, although believed to be representative of the selected configurations, will likely vary from the official vendor information, design standards, guarantee philosophy and conservatisms (margins).

WorleyParsons modeled the gasifier, acid gas removal, sulfur removal unit, and tail gas treatment unit with Aspen software based on models previously developed. The combined cycle performance was modeled with Gate Cycle based upon GE provided data on the gas turbine for other projects and various assumptions noted in the following sections. Overall, the models were exercised several times in an iterative fashion. This iteration included gas turbine requirements, which impacted the size of the gasifier.

The following sections briefly describe the selected configurations and their corresponding performance.

3.1.1 Gasification Block

The gasification plant is based on a 2-stage, entrained-flow, oxygen-blown, continuous slagging ConocoPhillips (CoP) E-Gas gasifier with conventional cold gas clean-up. The estimate of E-gas gasifier performance is based on data from COP and in-house models. Refinement of the expected gasifier performance based on OEM input from empirically derived test data, generated with similar coal rank/quality and oxidant purity to that used in this study, may result in a more efficient ash slag temperature profile.

Syngas humidification and compressor bleeds for ASU-GT integration were not utilized in this configuration.

A coal/ water slurry and a 95% oxygen rich stream are fed into the first stage of the E-Gas gasifier. The slurry concentration is 58% solids for the Black Butte coal. In this first stage, the coal slurry goes through an exothermic partial oxidation reaction to generate syngas and to provide heat to melt the coal ash and for the second stage gasification reactions. The molten ash falls through a tap at the bottom of the first stage gasification chamber into a water quench to form an inert slag. The syngas flows into the gasifier's second stage where additional coal slurry is injected. The coal is pyrolyzed in an endothermic reaction with the hot first stage syngas at a reduced temperature, to yield a syngas of enhanced heating value and composition. The gasifier cold gas efficiency is 76.1 with the design Black Butte coal. Current slurry splits of 82/18% have been demonstrated at Wabash [6] [7].

The syngas enters the syngas cooler to produce high pressure steam, in what amounts to a fire tube steam generator. This high pressure steam is utilized in both the gasification process as well as the steam bottoming cycle. Subsequently, particulates are removed by the hot/dry candle filters and are recycled to the gasifier. After additional cooling, the syngas is water scrubbed to remove chlorides, and passed through a catalyst to hydrolyze the COS so it can be removed in the Acid Gas Removal (AGR) train as H_2S.

A UOP Selexol absorbent system is used for the AGR system. Low sulfur gas from the AGR is preheated and sent to the power block. Acid Gas from the AGR is sent to the Claus plant and tail gas unit for maximum sulfur recovery. The oxygen enriched Claus plant is designed with both air and oxygen feeds. In the application presented here, excessive amounts of oxygen increases the temperature in the combustion chamber past the reasonable limits of the refractory and requires some air in lieu of oxygen.

A simplified block flow diagram and material balances of the gasification block are presented below.

Exhibit 3-1
E-Gas Gasification Block Process Flow Diagram

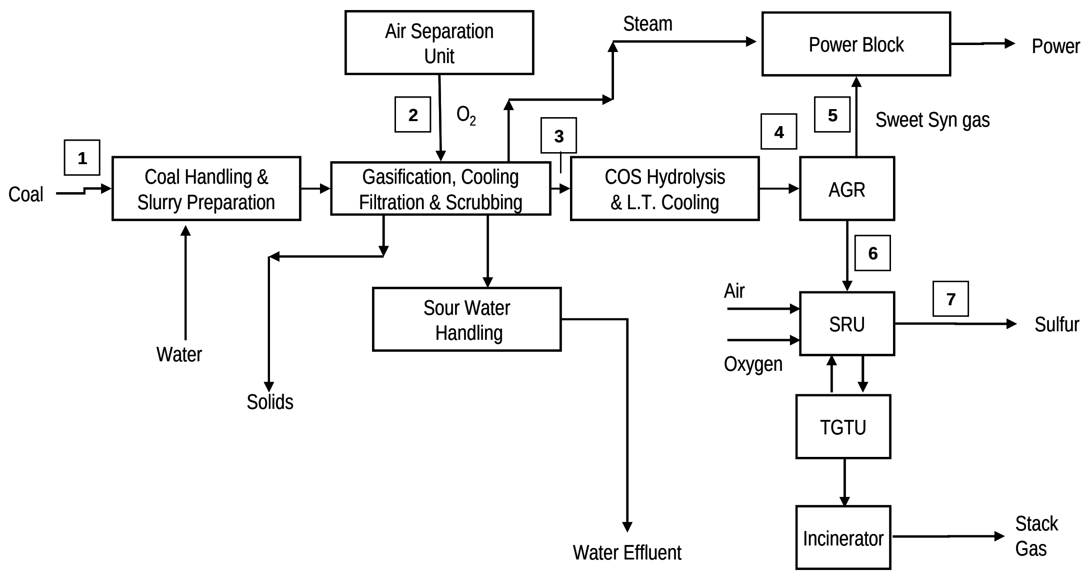


Exhibit 3-2
Black Butte Coal Gasification Block Material Balance for the Reid Gardner Site

Stream No.	1	2	3	4	5	6	7	8
	Coal Feed	Oxygen to Gasifier	Syn Gas Lvg Scrubber	Syn Gas Lvg LT Cool	Syn Gas Lvg AGR	Acid Gas Lvg AGR	Sulfur Lvg SRU	Tail Gas Lvg TGTU
LB mol/Hr	-	-	-	-	-	-	-	-
CO	-	-	16,180.34	16,180.07	16,178.45	1.62	-	0.05
H2	-	-	12,845.42	12,845.42	12,844.14	1.28	-	0.01
CO2	-	-	6,353.17	6,356.11	6,100.59	255.52	-	447.61
H2O	-	-	2,933.64	82.98	50.00	32.97	-	91.56
CH4	-	-	557.68	557.66	557.66	-	-	-
N2 + Ar	-	561.39	786.12	784.98	784.82	0.16	-	14.02
O2	-	10,666.42	-	-	-	-	-	-
H2S	-	-	64.90	70.19	0.60	73.59	-	0.06
COS	-	-	5.69	0.24	0.24	0.02	-	0.00
Sulfur	-	-	-	-	-	-	73.54	-
Total	**-**	**11,227.8**	**39,727.0**	**36,877.6**	**36,516.5**	**365.2**	**73.5**	**553.3**
Mol Wt	-	32.21	21.38	21.64	21.46	39.50	32.07	37.97
Lbs/hr	519,111	361,326	849,382	797,962	783,698	14,401	2,358	21,015
MMSCFD	-	102.34	362.12	336.15	332.86	3.33	-	5.04
Temp, °F	-	205	285	103	88	121	-	-
Press, psia	14.4	650.0	452.7	417.7	407.7	30.0	-	24.9

Notes:

1. Total acid gas to SRU includes other small streams not shown here.
2. Overall sulfur recovery is equivalent to approximately 99%.
3. Total sulfur production is estimated at 29. st/d.
4. Total solids are estimated at 39,236 lbs/day.
5. Approximately 0.047 st/day of SO_2 are discharged to the atmosphere from the TGTU incinerator.
6. Sulfur in the feed equals 2388 lb/hr (0.46 wt %).
7. Data is based on the design ambient conditions of 68 °F Dry Bulb / 50 Relative Humidity, at a site elevation of 1,700 ft.

Exhibit 3-3
Black Butte Coal Gasification Block Material Balance for the Valmy Site

Stream No.	1	2	3	4	5	6	7	8
	Coal Feed	Oxygen to Gasifier	Syn Gas Lvg Scrubber	Syn Gas Lvg LT Cool	Syn Gas Lvg AGR	Acid Gas Lvg AGR	Sulfur Lvg SRU	Tail Gas Lvg TGTU
LB mol/Hr	-	-	-	-	-	-	-	-
CO	-	-	15,202.21	15,201.95	15,200.43	1.52	-	0.04
H2	-	-	12,068.89	12,068.89	12,067.68	1.21	-	0.01
CO2	-	-	5,969.11	5,971.87	5,731.80	240.07	-	420.55
H2O	-	-	2,756.30	77.96	46.98	30.98	-	86.02
CH4	-	-	523.96	523.94	523.94	-	-	-
N2 + Ar	-	527.45	738.60	737.53	737.38	0.15	-	13.17
O2	-	10,021.61	-	-	-	-	-	-
H2S	-	-	60.97	65.95	0.57	69.14	-	0.06
COS	-	-	5.35	0.23	0.23	0.01	-	0.00
Sulfur	-	-	-	-	-	-	69.09	-
Total	**-**	**10,549.1**	**37,325.4**	**34,648.3**	**34,309.0**	**343.1**	**69.1**	**519.8**
Mol Wt	-	32.21	21.38	21.64	21.46	39.50	32.07	37.97
Lbs/hr	487,730	339,483	798,036	749,724	736,322	13,530	2,216	19,744
MMSCFD	-	96.16	340.23	315.83	312.73	3.13	-	4.74
Temp, °F	-	205	285	103	88	121	-	-
Press, psia	14.4	650.0	452.7	417.7	407.7	30.0	-	24.9

Notes:

1. Total acid gas to SRU includes other small streams not shown here.
2. Overall Sulfur recovery is equivalent to approximately 99%.
3. Total sulfur production is estimated at 27. st/d.
4. Total solids are estimated at 36,864 lbs/day.
5. Approximately 0.044 st/day of SO_2 are discharged to the atmosphere from the TGTU incinerator.
6. Sulfur in the feed equals 2244 lb/hr (0.46 wt %).
7. Data is based on the design ambient conditions of 50 °F Dry Bulb / 50 Relative Humidity, at a site elevation of 4,500 ft.

Exhibit 3-4
Black Butte Coal Gasification Block Material Balance for the Ely Site

Stream No.	1	2	3	4	5	6	7	8
	Coal Feed	Oxygen to Gasifier	Syn Gas Lvg Scrubber	Syn Gas Lvg LT Cool	Syn Gas Lvg AGR	Acid Gas Lvg AGR	Sulfur Lvg SRU	Tail Gas Lvg TGTU
LB mol/Hr	-	-	-	-	-	-	-	-
CO	-	-	14,427.84	14,427.59	14,426.15	1.44	-	0.04
H2	-	-	11,454.12	11,454.12	11,452.98	1.15	-	0.01
CO2	-	-	5,665.06	5,667.67	5,439.83	227.84	-	399.12
H2O	-	-	2,615.90	73.99	44.59	29.40	-	81.64
CH4	-	-	497.27	497.26	497.26	-	-	-
N2 + Ar	-	500.59	700.98	699.96	699.82	0.14	-	12.50
O2	-	9,511.13	-	-	-	-	-	-
H2S	-	-	57.87	62.59	0.54	65.62	-	0.05
COS	-	-	5.08	0.22	0.22	0.01	-	0.00
Sulfur	-	-	-	-	-	-	65.58	-
Total	**-**	**10,011.7**	**35,424.1**	**32,883.4**	**32,561.4**	**325.6**	**65.6**	**493.4**
Mol Wt	-	32.21	21.38	21.64	21.46	39.50	32.07	37.97
Lbs/hr	462,886	322,191	757,385	711,534	698,815	12,841	2,103	18,738
MMSCFD	-	91.26	322.90	299.74	296.80	2.97	-	4.50
Temp, °F	-	205	285	103	88	121	-	-
Press, psia	14.4	650.0	452.7	417.7	407.7	30.0	-	24.9

Notes:

1. Total acid gas to SRU includes other small streams not shown here.
2. Overall Sulfur recovery is equivalent to approximately 99%.
3. Total sulfur production is estimated at 25. st/d.
4. Total solids are estimated at 34,986 lbs/day.
5. Approximately 0.042 st/day of SO_2 are discharged to the atmosphere from the TGTU incinerator.
6. Sulfur in the feed equals 2129 lb/hr (0.46 wt %).
7. Data is based on the design ambient conditions of 45 °F Dry Bulb / 50 Relative Humidity,, at a site elevation of 6,100 ft.

The following table shows the predicted composition of the syngas leaving the cold gas clean up process system to be sent to the gas turbine. Note that the difference in Sulfur composition is due to the different sulfur capture requirements between the sites.

.Exhibit 3-5
E-Gas Gasification Block Black Butte Syngas Analysis

Constituent	**Concentration (Mol %) Syngas Composition**	
Location	Reid Gardner	Valmy and Ely
CO	44.30	44.30
CO_2	16.71	16.71
H_2	35.17	35.17
CH_4	1.53	1.53
H_2O	0.14	0.14
AR + N_2	2.15	2.15
H_2S + COS	0.0015	0.0023
Total	100.00	100.00

3.1.2 Power Block Configuration and Analysis

The power block configuration was a 2x1 combined cycle utilizing two GE 7FB gas turbines, two HRSG's and one steam turbine. The steam cycle conditions were set at 1800psi/1035°F/1050°F. A nitrogen diluent was utilized to increase the power production and to control NO_X. The nitrogen flow rate was limited by the GE turbine requirements.

The gas turbine combined cycle was modeled with GateCycle with syngas utilizing GE provided data for other projects.

As noted from various correspondences/ teleconferences with GE, the performances of the 7FB gas turbines are under development by GE. The actual performance based upon GE's design and guarantee philosophy is likely to vary from the performance estimated here. The performance estimates should be considered preliminary until refined by GE.

The power block heat balances for each site are presented in Appendix A. Also presented in Appendix A are the water balances for the design ambient operating condition for each site.

3.1.3 Performance Summary

The estimated overall IGCC plant performance is presented below.

Exhibit 3-6
Estimated IGCC Plant Performance Summary

Item	Description	Reid Gardner Station	Valmy Station	Ely Station	Remarks
A. Performance with ConocoPhillips E- Gas Technology					
1	Gross Plant Output (kW)				See Heat Balance Diagrams
a.	Gas Turbines, Each	211,434	199,720	189,592	
b.	Steam Turbine	274,648	263,321	250,993	
c.	**Total Gross Output**	**697,516**	**662,761**	**630,177**	
2	**Aux Loads and Losses (kW)**				
a.	Process Plant	114,280	107,550	102,130	
b.	Power Plant	14,520	13,750	13,050	
c.	**Total Aux Loads & Losses**	**128,800**	**4,648**	**115,180**	
3	**Fuel Consumption, MMBH - HHV**	**4,947**	**4,648**	**4,411**	Based upon Black Butte coal HHV: 9,530 - Btu/lb
4	**Net Plant Output (kW)**	**568,720**	**541,470**	**515,000**	
5	**Net Plant Heat Rate (Btu/kWhr - HHV)**	**8,700**	**8,585**	**8,570**	

3.1.4 Air Emissions

The air emissions from the IGCC plants are based on the following:

The Reid Gardner IGCC must meet LAER regulations.

- NO_X will be based on combustion controls and nitrogen dilution in the gas turbine to be less than 25 ppmvd @ 15% O_2 NO_X will be further reduced with SCR in the HRSG's to be less than 3.5 ppmvd @ 15% O_2. This will achieve 0.013 lb/MMBtu (HHV).
- Because of sulfur removal in the gasifier, SO_2 will be less than 2 ppmvd @ 15% O_2, which corresponds to 0.0064 lb/MMBtu (HHV).
- CO is expected to be controlled in the gas turbine combustor to be less than 25 ppmvd @ 15% O_2. This will achieve 0.057 lb/MMBtu (HHV)

The Valmy and Ely IGCC must meet BACT regulations.

- NOX will be based on combustion controls and nitrogen dilution in the gas turbine to be less than 25 ppmvd @ 15% O2 NOX will be further reduced with SCR in the HRSG's to be less than 15 ppmvd @ 15% O2. This will achieve 0.013 lb/MMBtu (HHV).
- Because of controls in the gasifier, SO_2 will be less than 2.5 ppmvd @ 15% O_2. This will achieve 0.013 lb/MMBtu (HHV).
- CO is expected to be controlled in the gas turbine combustor to be less than 25 ppmvd @ 15% O_2. This will achieve 0.057 lb/MMBtu (HHV).)

Exhibit 3-7
IGCC Stack Air Emissions

PLANT	Reid Gardner		Valmy		Ely	
Regulations	LAER		BACT		BACT	
Heat Consumed (HHV)	4,947 MMBtu / Hr		4,648 MMBtu/Hr		4,411 MMBtu/ Hr	
Pollutant	**lb/ MMBtu**	**tons/year**	**lb/ MMBtu**	**tons/year**	**lb/ MMBtu**	**tons/year**
SO_2	0.0064	120	0.013	225	0.013	215
NOx	0.013	240	0.056	960	0.056	920
CO	0.057	1050	0.057	490	0.057	930
Stack Particulates	0.0145	270	0.0145	250	0.0145	245

Notes:

1. Base load combined cycle emission at HRSG stack exit with syngas firing in the gas turbines. All emission data are estimated and subject to verification upon receipt of gas turbine exhaust emission data from GE. Also, the selection of type, location of the SCR module in the HRSG and any impact on availability, operation and maintenance will be verified during the detail design phase. No flare emissions are included.
2. PM for IGCC is based on the formation of ammonium bisulfate in light of the SCR/NH_3 requirement. This value will depend on the NOx level which needs to be verified with GE based upon the final design. After combustion, the power block does not use a particulate removal system; any particulate formed during gas turbine combustion as well as in the catalyst section of the HRSG pass directly through the stack. Particulate from each gas turbine was assumed at 15 lb/turbine.

The following shows stack parameters for the flue gas leaving each of the HRSG's. The stack velocity is based on a 20' – 0" stack diameter.

Exhibit 3-8
HRSG Stack Exit Parameters

Parameter	Reid Gardner Station	Valmy Station	Ely Station
Flow, 1000 Lb/Hr	3,980	3,730	3,530
Flow, 1000 ACFM	1,244	1,293	1,300
Temperature °F	248	248	248
Stack Velocity, fps	66.0	68.6	69.0

Unless otherwise noted, the above values apply to the gasifier while operating with the design coal at the design ambient temperature. The NO_X emissions are planned to be controlled by use of SCR catalyst in the HRSG. The location of the SCR catalyst must be coordinated with the HRSG Vendor during the detail design phase to minimize the SO_3 formation and to avoid the effects of sulfur poisoning. Provisions must also be kept in the design to accomplish cleaning of the HRSG surfaces downstream of the SCR modules for periodic cleaning of the ammonium bisulfate salts. No provision for CO catalyst is included in the design

The mercury level in the fuel will be reduced by approximately 90% or greater by an activated carbon bed from the trace levels contained in the fuel. Such a system has been successfully utilized at The Eastman Chemicals gasification facility on bituminous coal. [8].

In addition to the emissions from the combined cycle, there will be an additional SO_2 source from the Sulfur Recovery Unit/ Tail Gas Treatment Unit (SRU/TGTU) incinerator mentioned above in section 3.1.1.

3.1.5 Waste Streams

The estimated waste streams for the IGCC plant are summarized below.

Exhibit 3-9
IGCC Waste Streams

Waste Stream	Reid Gardner Station	Valmy Station	Ely Station
Waste Water Emissions			
Waste Water (not including storm water and sanitary discharge)	100 gpm	100 gpm	100 gpm
Sanitary Discharge	15 gpm	15 gpm	15 gpm
Gasifer and Process Plant Emissions			
Liquid Waste – Slag (50% water)	78,472 lb/hr	73,728 lb/hr	69,972 lb/hr

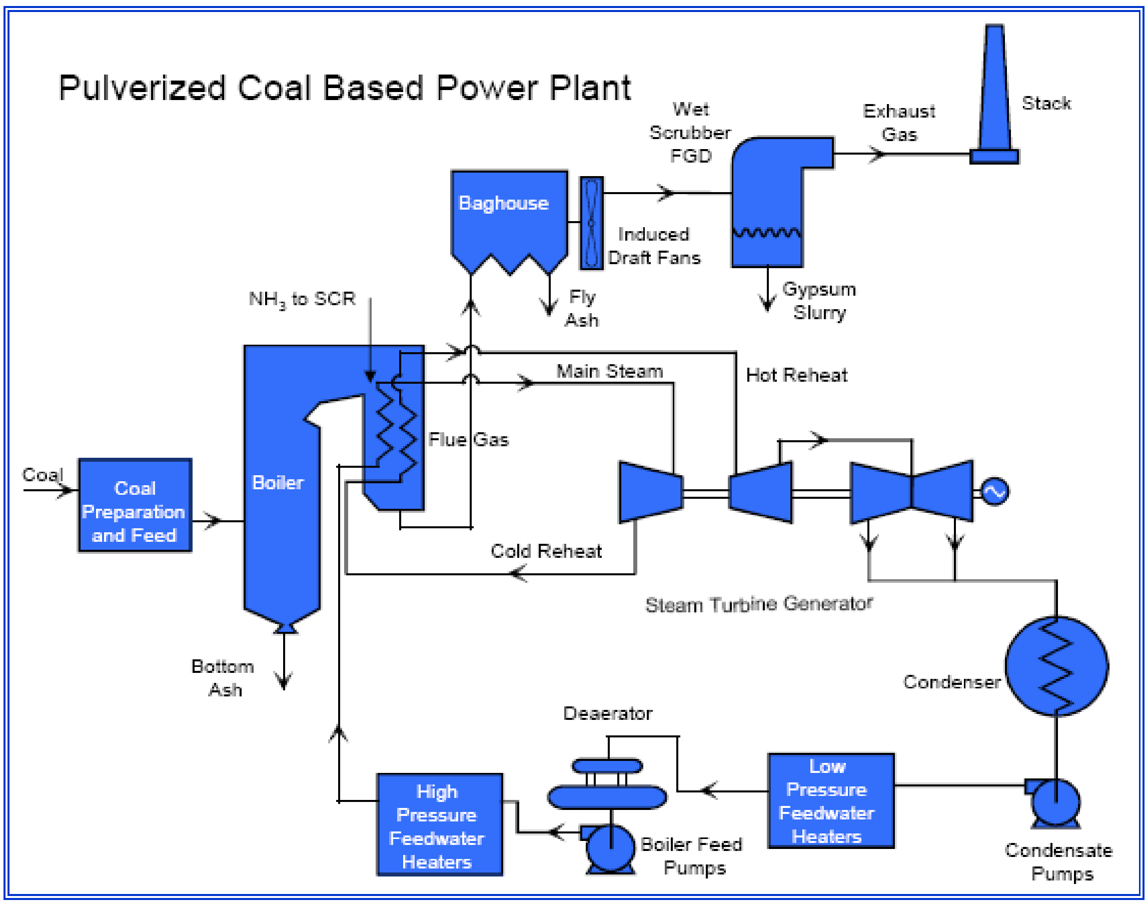
Note: Expected average waste stream values for power plant are for design conditions, base load operation.

3.2 Pulverized Coal Unit

The steam generator is a single reheat, supercritical PC-fired boiler that is a balanced draft, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air-heater. The steam conditions at the steam turbine are 3700 psig / 1100 / 1100 °F. The combustion system is equipped with low NO_x Burners (LNB), Selective Catalytic Reduction (SCR) for NO_x, and over fire air (OFA). The evaluation basis included that the power plant be designed for operation as a base-loaded unit.

The following shows a simplified schematic of a pulverized coal based power plant.

Exhibit 3-10
PC Based Power Plant



Sorce: WorleyParsons [9]

The Boiler comprises the following:

- Once through evaporator
- Forced draft (FD) and Primary air (PA) fans
- Water cooled furnace
- Air preheaters (Ljungstrom type)
- Induced draft (ID) fans
- Coal feeders and pulverizers
- Economizer
- Coal burners and ignitors/warmup system
- Dry Electrostatic Precipitator.

The Steam Cycle will include the following:

- Steam Turbine Generator.
- Feed Heater System.
- Deaerator
- Condensate System
- Demineralizer system
- The Scrubbing system will include the following:
- Scrubber
- Dewatering System
- Gypsum removal System

The Balance of plant includes the following items;

- Ash Handling
- Coal Handling
- Limestone Handling
- Ammonia for the SCR

3.2.1 Boiler Island

Feedwater and Steam

The feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the water wall circuits enclosing the furnace. After passing through the furnace circuit, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

Air and Combustion Products

Combustion air from the FD fans is heated in the air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying pulverized coal to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the pulverized coal, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The pulverized coal and air mixture flows to the coal nozzles at the various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow through the SCR, ESP, ID fan, FGD system, and stack.

Fuel Feed

The crushed coal is fed through feeders to each of the mills (pulverizers). The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls. No coal drying has been assumed in the system. The effect of coal moisture has been reflected in the heat rate calculation.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hopper design incorporates a water filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

The boiler employs multiple coal nozzles arranged in multiple elevations. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, overfire air nozzles may be provided to further stage combustion and thereby minimize NOx formation.

Pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

Air Preheaters

The steam generator is furnished with vertical-shaft regenerative type air preheaters. These units are driven by electric motors through gear reducers.

3.2.2 Steam Cycle

Steam Turbine

The steam turbine generator is a single reheat type consisting of a high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler enters the turbine. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The first reheat steam flows through the reheat stop valves and intercept valves and enters the IP section. After passing through the IP section, the steam flows through the two LP section, exhausting into a single duct which conveys the exhaust steam to the water cooled condenser and to the air cooled condenser.

Condensate and Feedwater System

The turbine exhaust steam is condensed by one water cooled condenser and one air cooled condenser. The two condensers are sized to each condense one half of the exhaust steam at the annual average ambient conditions. During colder weather the air cooled condenser will have a higher relative duty, and during hot weather the water cooled condenser will have higher relative duty. This configuration reduces the annual water consumption by about one half as compared to a totally water cooled system, while minimizing the performance penalty associated with the air cooled condenser at high ambient temperatures. The condensate from the air cooled condenser flows by gravity to the hotwell of the water cooled condenser.

All of the condensate is pumped from the hotwell by the condensate extraction pumps through four closed LP feedwater heaters and up to the DC heater. The DC heater acts as a deaerator during start-up and low load operation. During higher load operation the vents are closed to operate with oxygenated feedwater treatment. A 100% condensate polisher is used at all times to maintain the required condensate quality.

The electric driven single-stage, low speed feed booster pump takes suction on the DC heater and provides the necessary NPSH for the high-speed turbine driven feed pump. The feedwater flows through 3 HP feedwater heaters and is delivered to the economizer of the boiler at a temperature of about 560 °F.

Cooling System

The function of the cooling system is to cool the condenser and to supply cooling water to the water cooled condenser and to the closed cooling water heat exchangers. The system consists of a combined wet and dry cooling system. There will be a wet and a dry cooling system operating in parallel to share the heat rejection duty, while reducing water consumption to match the specific amount available for cooling. Exhaust steam coming off a steam turbine generator is immediately separated into two streams. One stream flows into a surface condenser while the other is directed to an air cooled condenser. Condensate recovered in the surface condenser and the air cooled condenser can be collected in a common hotwell. The steam distribution between the two units is controlled without any requirement for valves or dampers. Water consumption is controlled by the distribution of heat load between the two condensers

3.2.3 Balance of Plant Description

The balance of plant consists of the following areas:

Coal Handling and Preparation

The function of the coal handling and preparation system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the inlets of the prepared fuel silos.

Fly Ash Removal

Fly ash is removed from the stack gas through a baghouse filter.

Ash Handling

The function of the ash handling system is to convey, prepare, store, and dispose of the fly ash and bottom ash produced on a daily basis by the boiler.

Limestone Handling and Reagent Preparation System

The function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. The scope of the system is from the storage pile up to the limestone feed system. The system is designed to support continuous baseload operation. Truck roadways, turnarounds, and unloading hoppers are included in this reference plant design.

The limestone is unloaded onto a storage pile located above vibrating feeders. The limestone is fed onto belt conveyors via vibrating feeders and then to day bins equipped with vent filters. Each day bin supplies a 100 percent capacity size ball mill via a weigh feeder. The wet ball mill grinds the limestone. Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydroclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydroclone underflow with oversized limestone is directed back to the mill for further grinding. The hydroclone overflow with correctly sized limestone is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

Flue Gas Desulfurization System

Flue Gas Desulfurization (FGD) system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and waist solids for disposal or gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 content prior to release to the environment.

The flue gas exiting the air preheater section of the boiler passes through the Baghouse, then through the ID fans and into the absorber module which operates with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent The scrubbed flue gas exits at the top of the absorber vessel and is routed to the plant stack.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite, contained in the slurry, to calcium sulfate (gypsum). This FGD system is designed for wet stack operation.

3.2.4 Plant Performance

The estimated overall plant performance for the PC configuration is presented in Exhibit 3-11 . is the performance is based upon a supercritical reheat cycle with 3700 psig/1100/1100F throttle conditions and a eight heater feed heating cycle. The boiler efficiency was calculated to be 86.3% at the Valmy site and 86.8% at the Reid Gardner based on the coal analysis for Black Butte. The PC unit heat balances for each site are presented in Appendix B. Also presented in Appendix BA are the water balances for the design ambient operating condition for each site.

Exhibit 3-11
Estimated Plant Performance Summary – PC Fired Boiler

Item	Description	Reid Gardner	Valmy Station	Remarks
A. Performance with Pulverized Coal Unit				
1	Gross Steam Turbine Output (kW)	641,760	641,670	See Heat Balance Diagrams
2	Auxiliary Loads and Losses (kW)	41,260	41,250	
3	New Plant Output (kW)	600,500	600,420	
4	Fuel Consumption, MMBH - HHV	5,370	5,254	Based upon Black Butte Coal HHV: 9,530 - Btu/lb
5	Net Plant Heat Rate (Btu/kWhr - HHV)	8,941	8,750	

The boiler efficiency, turbine output, and auxiliary loads and losses were calculated by WorleyParsons standard methodology using historical data and experience. Vendor input was not received for major equipment. Notwithstanding the lack of vendor input, WorleyParsons has good confidence in the calculations and estimates the uncertainty for output to be less than 3% and uncertainty for heat rate to be less than 5%.

3.2.5 Environmental Control

The environmental control equipment was defined to meet BACT emission rates for the Valmy site, and LAER emission rates for the Reid Gardner site. For the Valmy site this will require sulfur capture of 77%, and for the Reid Gardner site required sulfur capture will be 93%.

Estimated stack emission rates and annual emissions are based on an annual capacity factor of 85% for full-load operation (7,450 hours/yr). These estimates are presented in Exhibit 3-12

Exhibit 3-12
Estimated PC Stack Emissions

PLANT	Valmy		Reid Gardner	
Regulations	BACT		LAER	
Heat Consumed (HHV)	5,254 MMBtu/Hr		5,370 MMBtu / Hr	
Pollutant	**lb/ MMBtu**	**tons/year**	**lb/ MMBtu**	**tons/year**
SO_2	0.2	3914	0.06	1200
NOx	0.15	2936	0.07	1400
CO	0.15	2936	0.1	2000
Stack Particulates	0.015	294	0.012	240

3.2.6 Waste Streams

WorleyParsons estimated the water balance based on experience and historical data. It is customary for WorleyParsons to reuse waste water streams from one process in another process within the plant. An example is to direct boiler drains and blowdowns to the cooling tower, and to direct cooling tower blowdown to the FGD system. The basis also included FGD blowdown being used for dust suppression on the coal pile and roadways. Because of the extensive internal reuse of water within the plant, there should be no liquid waste streams from the plant. In fact, both the cooling tower and the FGD are expected to operate with lower cycles of concentration than what would be possible in order to provide enough water flow to the next downstream system. Never the less, a storage, or surge basin to accommodate short-term fluctuations in water flow is included in the design. While there may be some evaporation from this basin, the water balances have not accounted for any evaporation to reduce the waste water quantity.

4 Project Cost Estimate

This Project Cost Estimate section identifies the approach used to determine the capital cost and the average annual operating costs of both the ConocoPhillips E-Gas gasifier and the Supercritical PC cases.

4.1 Capital Cost Estimates

The approach for developing the capital cost for each E-Gas gasifier and PC case configuration is similar except for the selection of the reference cost model for each technology. These reference cost models produce Total Plant Cost (TPC) results on the basis of the plant performance and specified scope requirements for each technology at each site.

The battery limits for the estimates extend from the coal and limestone unloading system to the high side of the main power transformer. The estimates are developed at the level of Total Plant Cost (TPC) that includes the cost of equipment, materials, installation, professional services (engineering, CM and startup assistance) and process contingency (gasification only) plus project contingency. The construction labor is based on an approach of multiple union labor based contracts. Process contingency is applied to only the Bare Erected Cost of the gasifier package cost. The project contingency is determined by applying a range of factors to systems or components depending on the likelihood that their costs will change. The composite average contingency for the IGCC cases is 15.0% (process and project) and for the PC cases is 10.2%.

The estimated cost for each option is the cost of installed equipment and the supporting process materials, foundations, structures and facilities that results in a complete operating unit. In this brownfield site evaluation, the installed cost of all equipment and materials is included in the estimate. The adjacent unit and site infrastructure is assumed to exist at the new plant boundary.

The TPC level of costs does not include all of the direct and indirect costs needed to reach the Total Capital Requirement (TCR) level of cost. Listed below are major cost areas that should be considered for a total TCR cost.

- Switchyard Cost (by Nevada Power/Sierra Pacific)
- Infrastructure to New Plant Boundary (e.g., natural gas pipeline or rail spur), if not existing
- EPC Contractor Approach Additional Cost (about +8.5% of TPC cost, based on previous in-house analyses)
- EPC Contractor Risk (the cost could vary widely depending on the specific conditions at the time of award)
- Sales Tax
- Escalation During Construction
- Project Financing Costs

- Land
- Preproduction Costs
- Inventory Capital & Spare Parts Inventory
- Owners Costs

The selected models were adjusted and/or updated to represent the site specific characteristics of these cases. The major changes are listed below:

- Estimate cost year was adjusted to January, 2006.
- Labor was adjusted to a Reno and Las Vegas, Nevada union basis.
- Specific design, scope and capacities identified in Section 2 and Section 3.

The cost values for the combustion turbine packages and the HRSG's is based on vendor furnished price for the equipment.

The total cost result for each gasification and PC case is included in the Exhibit ES-1. Cost results supporting the summary values are included in Appendix C. A list of assumptions (Capital and O&M Cost Basis) used in the development of the capital costs is also included in the Appendix.

4.2 Annual Operation & Maintenance Costs

Average annual Fixed Operating Costs (FOC) and Variable Operating Costs (VOC) excluding fuel costs were estimated for each case.

The FOC consists of operating labor, maintenance labor, and allowance for administrative and support labor. The operating labor cost is developed on the basis of the average number of operating jobs (OJ) on a daily basis. The maintenance labor is determined as a percent of total maintenance. The total maintenance cost is determined for each component or system as an average annual cost based on the associated capital cost. The administrative and support labor (Labor O-H Charge) is determined as a percent of the total operating and maintenance labor. The maintenance material is the remaining cost of maintenance after the maintenance labor is allocated to FOC.

The VOC consists of, maintenance material cost, consumables, cost of disposal and credit for the sulfur by-product (in this application, no credit was recognized for the by-products). Sulfur is produced in the IGCC cases but the value of this by-product was excluded based on the Design Basis Document. The PC cases produce both ash and gypsum but these are both disposed of in an on-site landfill. The consumables costs are based on the estimated daily consumption, applicable unit cost and adjustment of cost results for the assumed plant operating capacity factor.

The O&M unit cost results for each IGCC and PC case are included in Exhibit ES-1. Cost results supporting the summary values are included in Appendix C.

5 References

1 "Updated Market Based Advanced Coal Power Systems Comparison Study" Ronald L. Schoff et. al. Presented at the 31st International Technical Conference on Coal Utilization and Fuel Systems May 21 - 26 2006 Clearwater, FL.

2 "Updated Market Based Advanced Coal Power Systems Comparison Study" Ronald L. Schoff et. al. Presented at the 31st International Technical Conference on Coal Utilization and Fuel Systems May 21 - 26 2006 Clearwater, FL.

3 "Updated Market Based Advanced Coal Power Systems Comparison Study" Ronald L. Schoff et. al. Presented at the 31st International Technical Conference on Coal Utilization and Fuel Systems May 21 - 26 2006 Clearwater, FL.

4 "Final Technical Report to the Department of Energy" Piñon Pine IGCC Project DOE Award Number (DE-FC21-92MC29309) Reporting Period August 1, 1992 to January 1, 2001. Sierra Pacific Resources Tracy Power Station 191 Wunotoo Rd. Sparks, NV 89434

5 U.S. Environmental Protection Agency, Green Book, Currently designated non-attainment areas for all criteria pollutants, September 29, 2005, http://www.epa.gov/oar/oaqps/greenbk/ancl.html#NEVADA

6 "ConocoPhillips Gasification 2004," presented at the Gasification Technologies Conference 2004, Washington DC October 4, 2004, by Phil Amick.

7 "Wabash River Coal Gasification Repowering Project. Final Technical Report." Prepared by the Men and Women of Wabash River Energy Ltd. Prepared for the U. S. Department of Energy Office of Fossil Energy National Energy Technology Laboratory, Morgantown, WV. August 2000.

8 "Coal Gasification: What are You Afraid of" POWER-GEN International Conference 2004 November 30 – December 2, 2004, Nathan Moock and William Trapp of Eastman Gasification Services Company

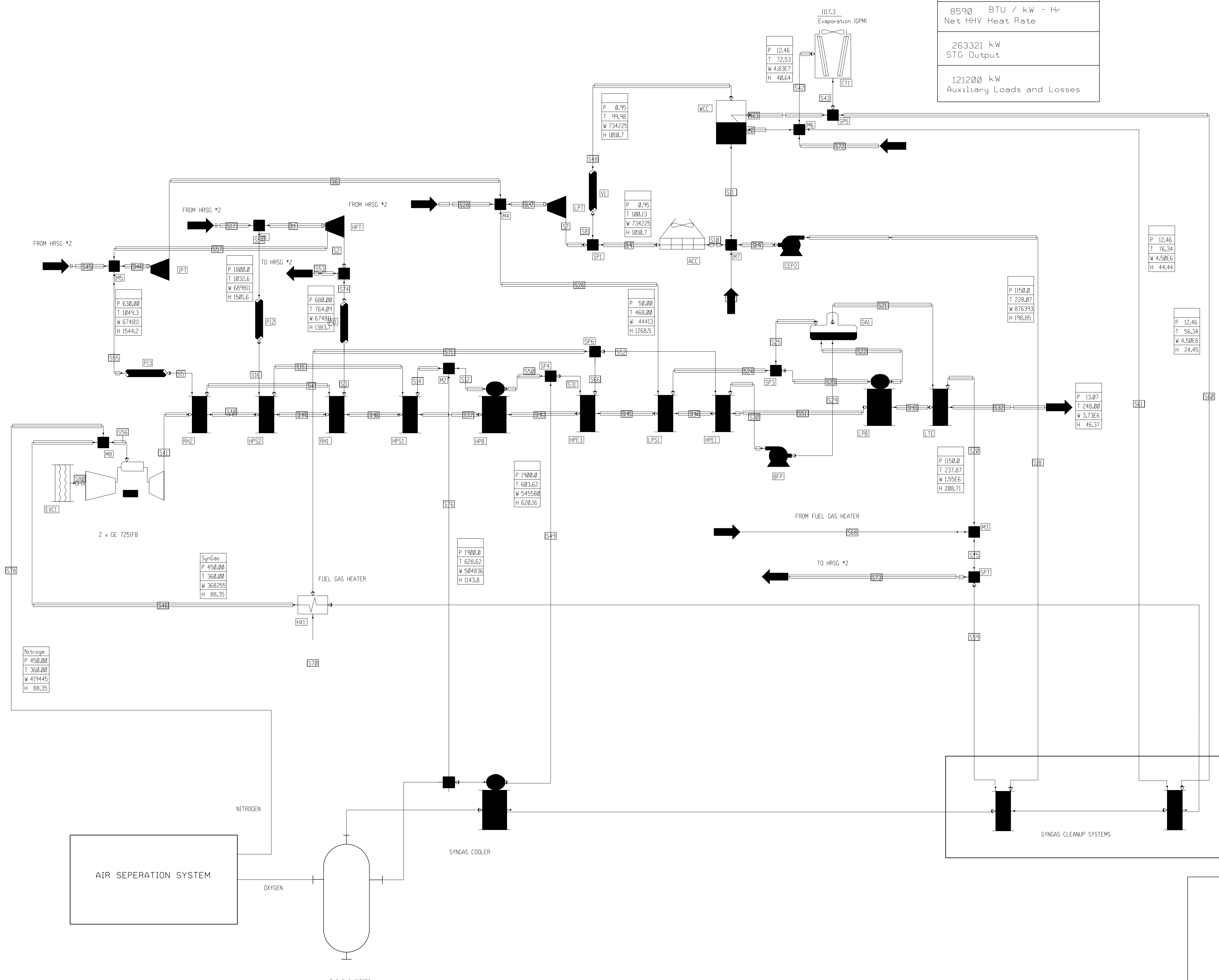
9 "Advanced Pulverized Coal Power Plant Technologies" prepared for "Power Production in the Next Century" June 15-16, 1999 By Michael Delallo, P.E.

Appendix A Gasifier IGCC Balances: Heat and Mass Balances

541.56 MW	Net Plant Output
8590 BTU / kW - Hr	Net HHV Heat Rate
263321 kW	STG Output
121200 kW	Auxiliary Loads and Losses

NOTES:

1. THE AMBIENT CONDITIONS ARE 50 DEG F, 50% RH AND 4500 FT ASL.
2. THE HYBRID COOLING SYSTEM IS SIZED FOR 50% DRY COOLING AND 50% WET COOLING.
3. PERFORMANCE IS ESTIMATED BASED ON E-GAS GASIFIER BURNING BLACK BUTTE COAL AND GE 7251FB COMBUSTION TURBINE.



LEGEND

P = PRESSURE (PSIA)

T = TEMPERATURE (DEG F)

W= FLOW RATE (LBM/HR)

H = SPECIFIC ENTHALPY (BTU/LBM)

PRELIMINARY STATUS / DATE	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS, REVIEWED NOT CHECKED.
APPROVED STATUS / DATE	REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
ORIGINATING PERSONNEL	PROFESSIONAL ENGINEER'S SEAL
DRAWN BY	
CHECKED BY	
LEAD DESIGNER	
ENGINEER/TECH SPECIALIST	
PROJECT ENGINEERING MANAGER	
PROJECT MANAGER	ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE: STATE: LIC. NO.: DATE:

WorleyParsons
resources & energy

NEVADA POWER / SIERRA PACIFIC
VALMY STATION
IGCC OPTION - 50 DEG F

SCALE: NONE — DRAWING SIZE: D (24" x 36")

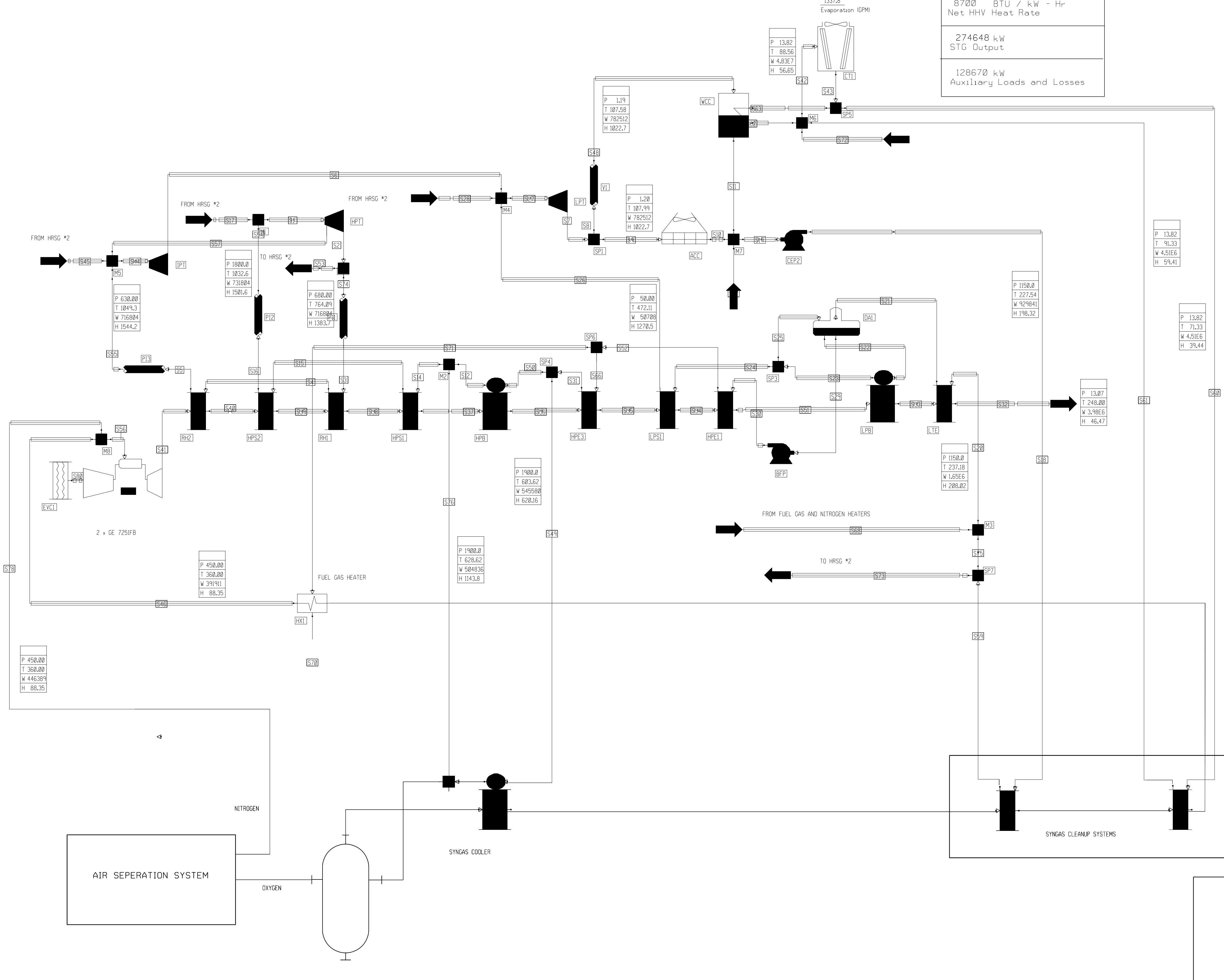
WORLEYPARSONS DWG. NO.: NPSP-1-SK-ME-306-1159 — REV: A

DWG-FILE: swslarch03d.fil
DWG-DATE: 23-Nov-05 10:44

568.84 MW	Net Plant Output
8700 BTU / kW - Hr	Net HHV Heat Rate
274648 kW	STG Output
128670 kW	Auxiliary Loads and Losses

NOTES:

1. THE AMBIENT CONDITIONS ARE 68 DEG F, 50% RH AND 1690 FT ASL.
2. THE HYBRID COOLING SYSTEM IS SIZED FOR 50% DRY COOLING AND 50% WET COOLING.
3. PERFORMANCE IS ESTIMATED BASED ON E-GAS GASIFIER BURNING BLACK BUTTE COAL AND GE 7251FB COMBUSTION TURBINE.



LEGEND

P = PRESSURE (PSIA)

T = TEMPERATURE (DEG F)

W= FLOW RATE (LBM/HR)

H = SPECIFIC ENTHALPY (BTU/LBM)

PRELIMINARY STATUS — DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

APPROVED STATUS — DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

ORIGINATING PERSONNEL — PROFESSIONAL ENGINEER'S SEAL

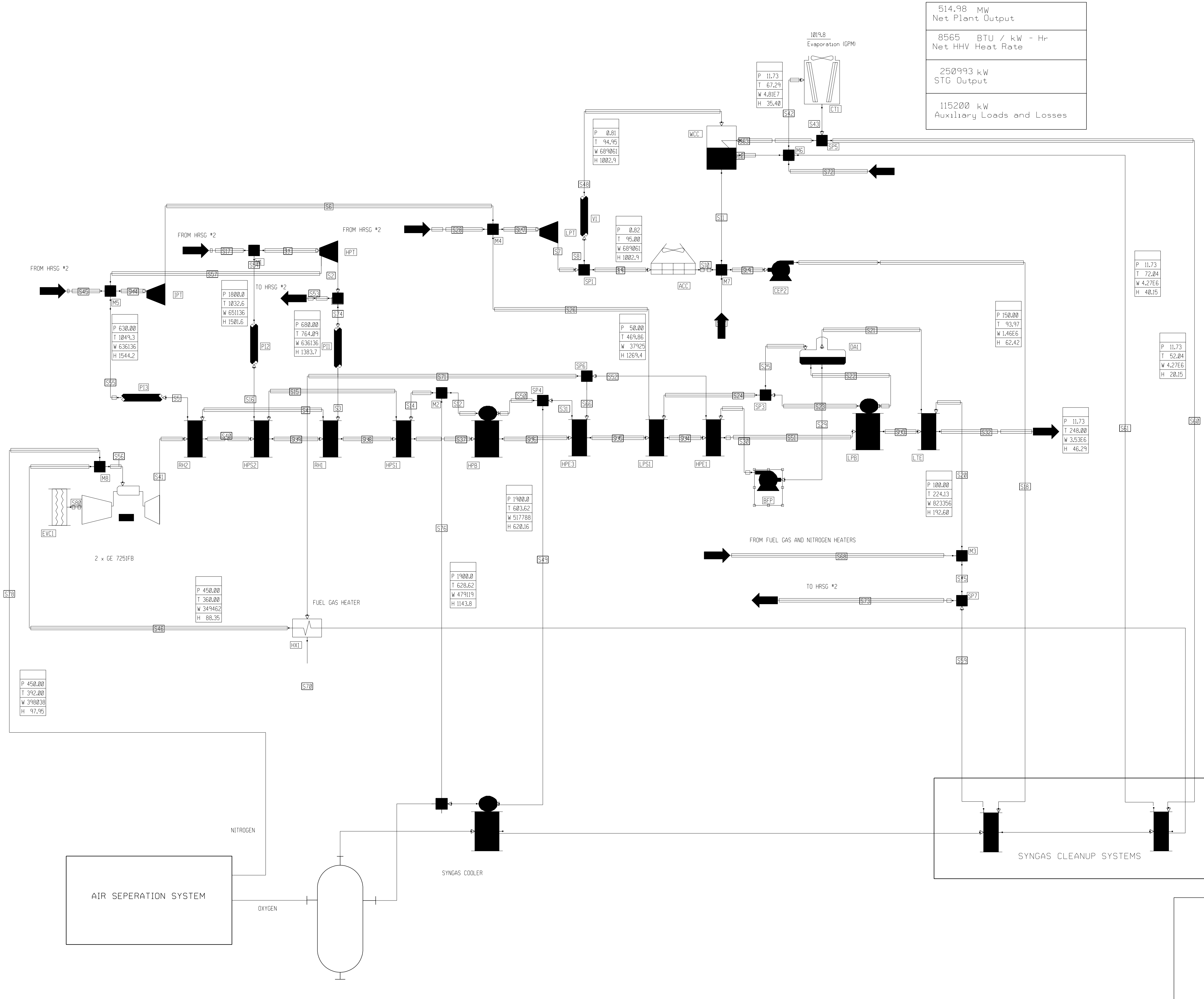
DRAWN BY / CHECKED BY / LEAD DESIGNER / ENGINEER/TECH SPECIALIST / PROJECT ENGINEERING MANAGER / PROJECT MANAGER

WorleyParsons resources & energy

NEVADA POWER / SIERRA PACIFIC
REID GARDNER STATION
IGCC OPTION - 68 DEG F

SCALE NONE — DRAWING SIZE D (24" x 36")

WORLEYPARSONS DWG. NO. NPSP-2-SK-ME-306-1159 — REV A



NOTES:

1. THE AMBIENT CONDITIONS ARE 45 DEG F, 50% RH AND 6100 FT ASL.
2. THE HYBRID COOLING SYSTEM IS SIZED FOR 50% DRY COOLING AND 50% WET COOLING.
3. PERFORMANCE IS ESTIMATED BASED ON E-GAS GASIFIER BURNING BLACK BUTTE COAL AND GE 7251FB COMBUSTION TURBINE.

LEGEND

P = PRESSURE (PSIA)

T = TEMPERATURE (DEG F)

W= FLOW RATE (LBM/HR)

H = SPECIFIC ENTHALPY (BTU/LBM)

PRELIMINARY STATUS — DATE — REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.

APPROVED STATUS — DATE — REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

ORIGINATING PERSONNEL / PROFESSIONAL ENGINEER'S SEAL

DRAWN BY

CHECKED BY

LEAD DESIGNER

ENGINEER/TECH SPECIALIST

PROJECT ENGINEERING MANAGER

PROJECT MANAGER

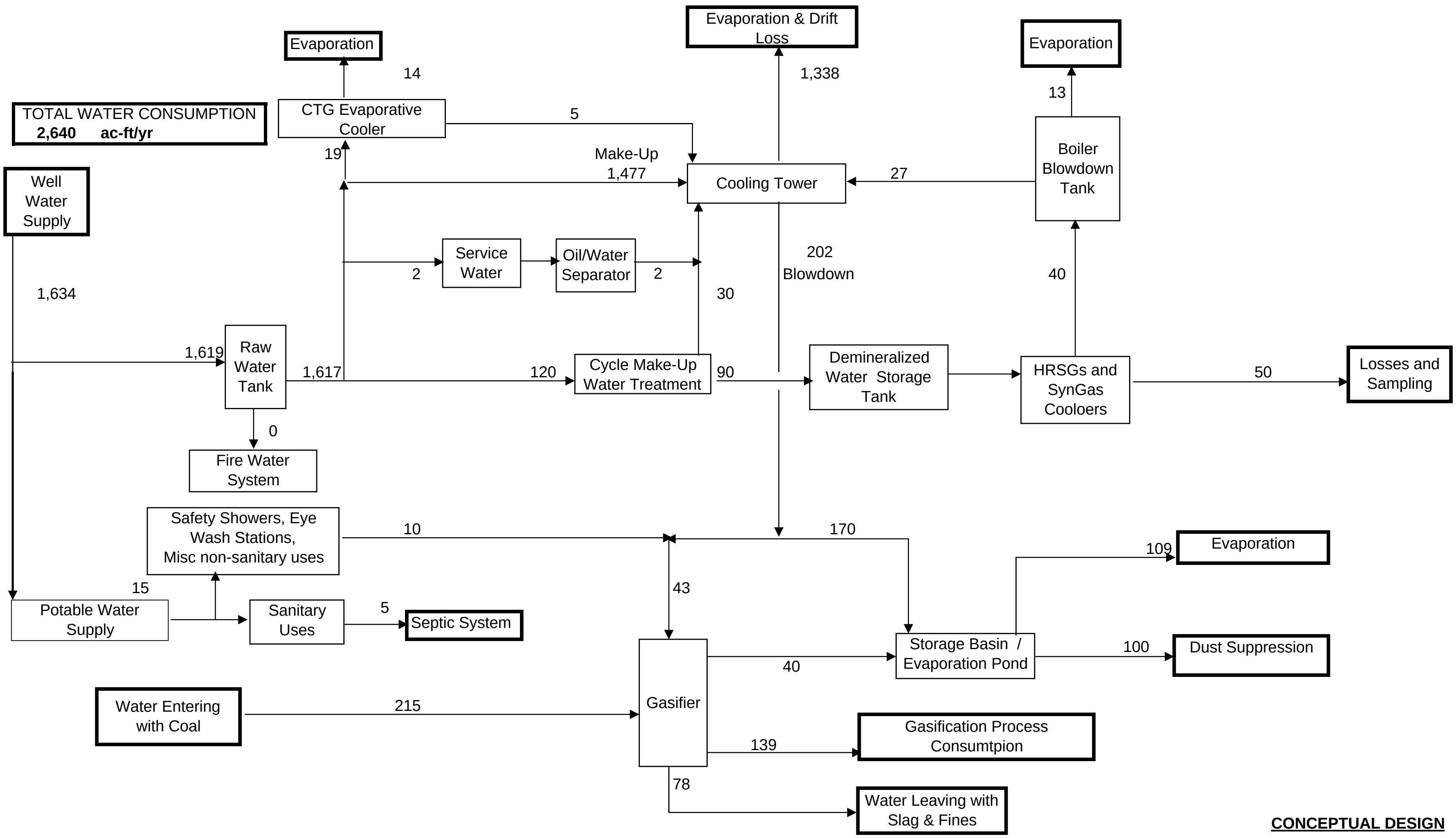
WorleyParsons
resources & energy

NEVADA POWER / SIERRA PACIFIC
ELY STATION
IGCC OPTION - 45 DEG F

SCALE NONE — DRAWING SIZE D (24" x 36")

WORLEYPARSONS DWG. NO. NPSP-3-SK-ME-306-1159 — REV A

DWG-FILE: swslarch03d.fil
DWG-DATE: 23-Nov-05 10:44

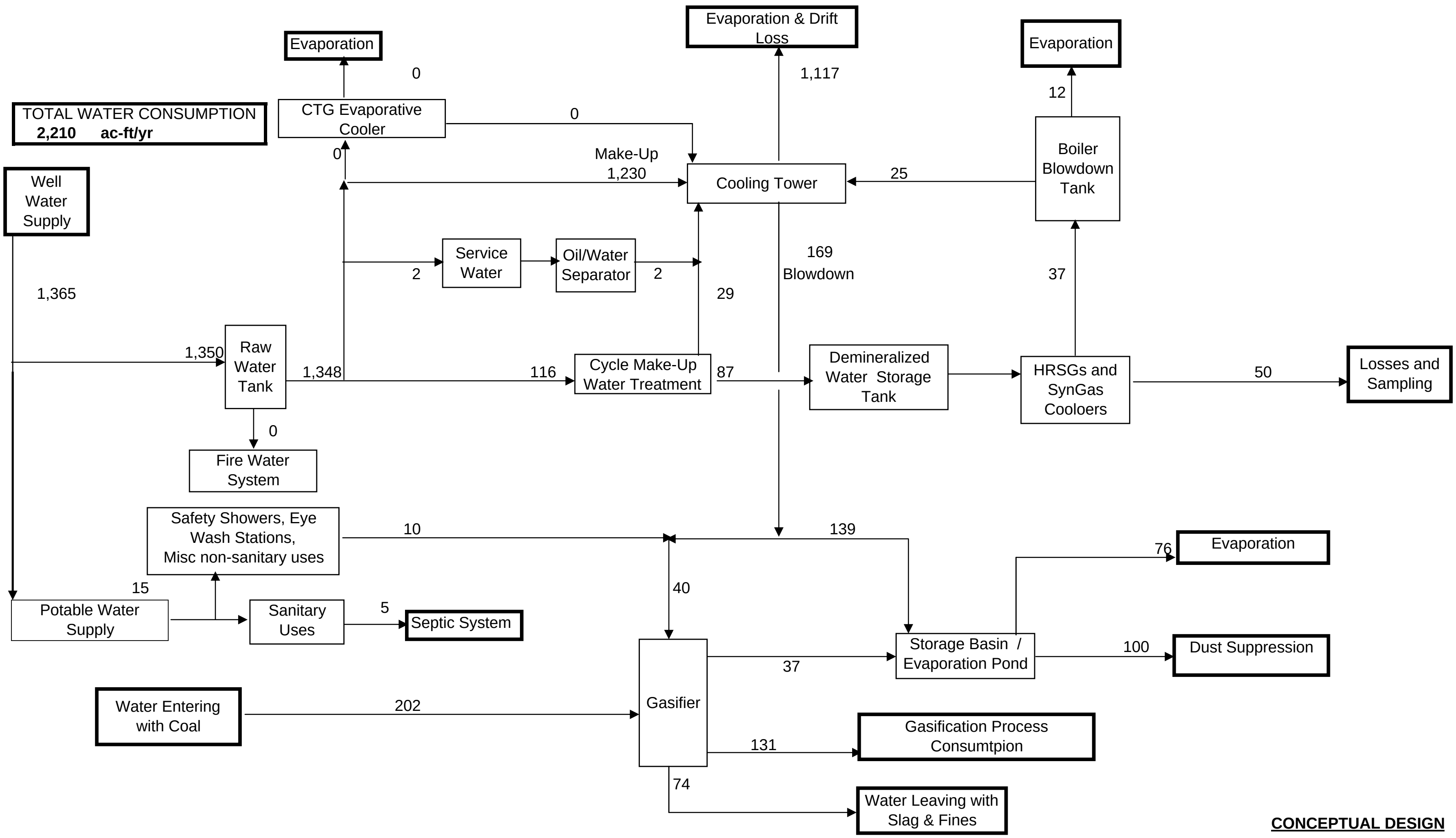


CONCEPTUAL DESIGN

Notes:
1. The water balance is based on a IGCC plant with ConocoPhillip Gasifier.
2. Assumes RO / EDI type Demin Plant
3. Cooling Tower cycles of Concentration is estimated at 8.
4. Blowdowns from the HRSGs and SynGas Cooler estimated a 0.5% total.

Units: All flows are in GPM unless otherwise noted.

WorleyParsons		
Nevada Power - Reid Gardner Site		
Preliminary Water Balance 2x1 - 7FB CTGs, Syn Gas Firing - Design Case 68 Degrees, Base Load, Unfired HRSG		
DWG No: NPSP-2-305-1159	Rev A	Date: 3/15/2006



CONCEPTUAL DESIGN

Notes:

1. The water balance is based on a IGCC plant with ConocoPhillip Gasifier.
2. Assumes RO / EDI type Demin Plant
3. Cooling Tower cycles of Concentration is estimated at 8.
4. Blowdowns from the HRSGs and SynGas Cooler estimated a 0.5% total.

Units: All flows are in GPM unless otherwise noted.

WorleyParsons		
Nevada Power - Valmy Site		
Preliminary Water Balance 2x1 - 7FB CTGs, Syn Gas Firing - Design Case 50 Degrees, Base Load, Unfired HRSG		
DWG No: NPSP-1-305-1159	Rev A	Date: 3/15/2006

Appendix B Pulverized Coal Unit Balances: Heat and Mass Balances

NOTES:

1. THE AMBIENT CONDITIONS ARE 68 DEG F, 50% RH AND 1690 FT ASL.

2. THE HYBRID COOLING SYSTEM IS SIZED FOR 50% DRY COOLING AND 50% WET COOLING.

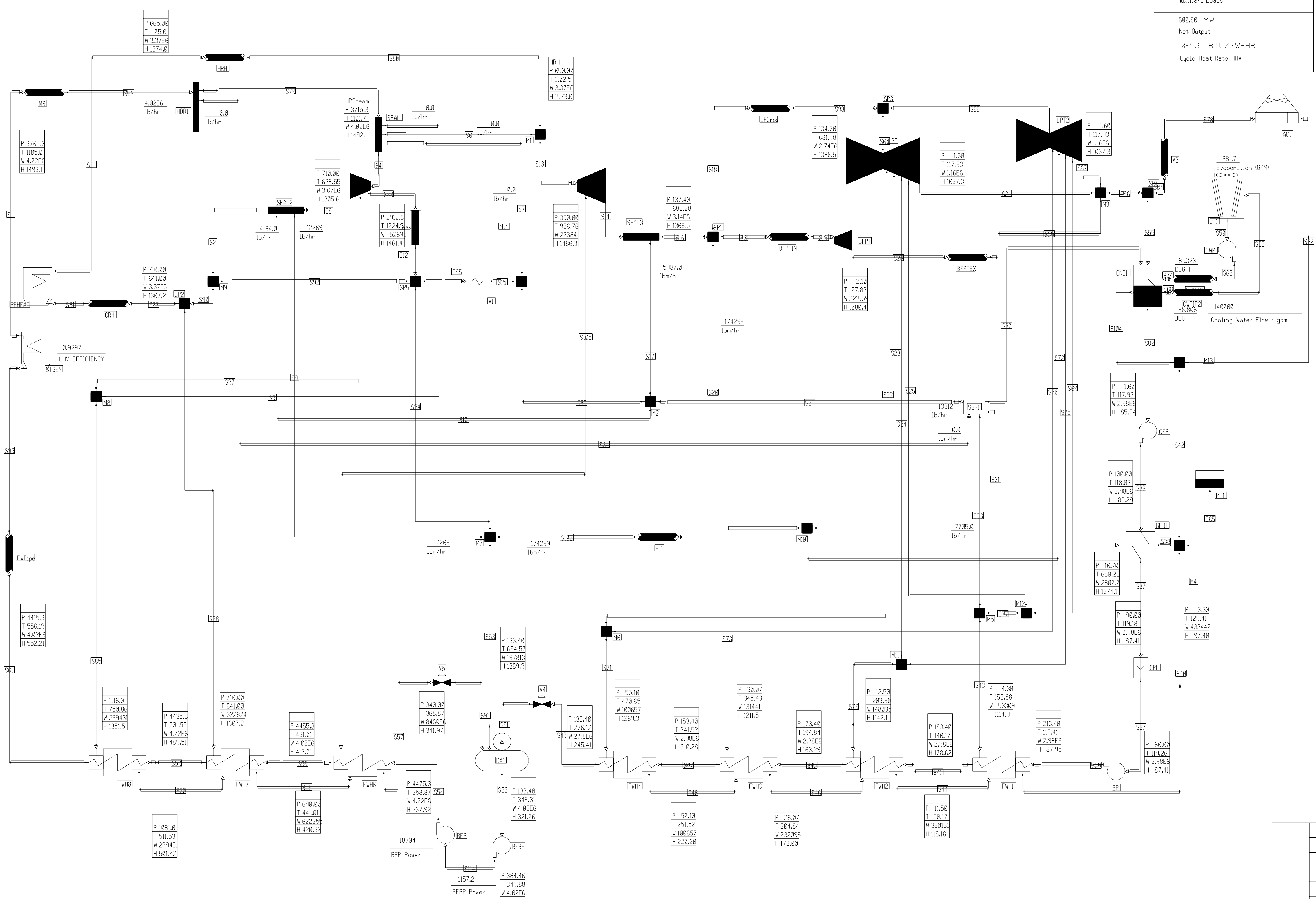
3. AUXILIARY POWER IS ESTIMATED AT 6.3% OF STEAM TURBINE OUTPUT.

4. BOILER HHV EFFICIENCY IS ESTIMATED AT86.8%

Steam Cycle Performance

5369.3 MMBTU/HR	Steam Generator Heat Input
641760 kW	STG Output, kW
41256 kW	Auxiliary Loads
600.50 MW	Net Output
8941.3 BTU/kW-HR	Cycle Heat Rate HHV

Nevada Power - Reid Gardner Station



LEGEND

P = PRESSURE (PSIA)

T = TEMPERATURE (DEG F)

W= FLOW RATE (LBM/HR)

H = SPECIFIC ENTHALPY (BTU/LBM)

PRELIMINARY STATUS LDE	DATE	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
APPROVED STATUS LDE	DATE	REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

ORIGINATING PERSONNEL	PROFESSIONAL ENGINEER'S SEAL
DRAWN BY	
CHECKED BY	
LEAD DESIGNER	
ENGINEER/TECH SPECIALIST	
PROJECT ENGINEERING MANAGER	
PROJECT MANAGER	ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE:________ STATE:________ LIC. NO.:________ DATE:________

WorleyParsons
resources & energy

PROJECT MANAGER
PROJ ENGR MANAGER
LEAD DISC ENGINEER
ENGINEER/ TECH. SPEC.
LEAD DESIGNER
CHECKED
DRAWN
DATE
REV

NEVADA POWER / SIERRA PACIFIC
REID GARDNER STATION
SUPERCRITICAL PC OPTION - 68 DEG F

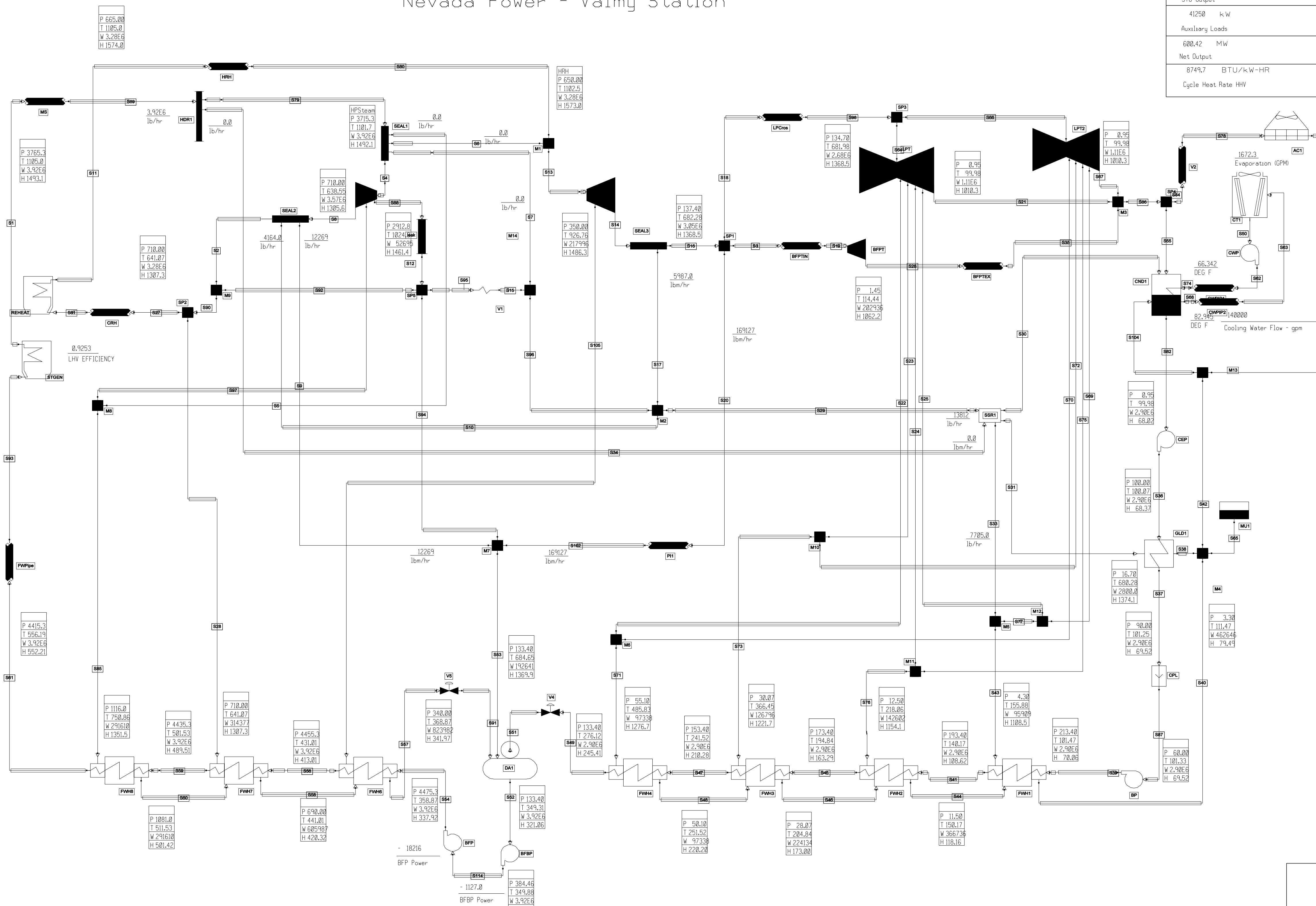
SCALE NONE | DRAWING SIZE D (24" x 36")

WORLEYPARSONS DWG. NO. NPSP-2-SK-ME-306-2159 | REV A

FAC | PIPING | I & C | ELECT | MECH | CIVIL | STRUC

DWG-FILE: swslarchD3d.fil
DWG-DATE: 23-Nov-05 10:44

Nevada Power - Valmy Station



Steam Cycle Performance

5253.5 MMBTU/HR	Steam Generator Heat Input
641667 kW	STG Output
41250 kW	Auxiliary Loads
600.42 MW	Net Output
8749.7 BTU/kW-HR	Cycle Heat Rate HHV

NOTES:

1. THE AMBIENT CONDITIONS ARE 50 DEG F, 50% RH AND 4500 FT ASL.
2. THE HYBRID COOLING SYSTEM IS SIZED FOR 50% DRY COOLING AND 50% WET COOLING.
3. AUXILIARY POWER IS ESTIMATED AT 6.3% OF STEAM TURBINE OUTPUT.
4. BOILER HHV EFFICIENCY IS ESTIMATED AT86.3%.

LEGEND

P = PRESSURE (PSIA)

T = TEMPERATURE (DEG F)

W= FLOW RATE (LBM/HR)

H = SPECIFIC ENTHALPY (BTU/LBM)

PRELIMINARY STATUS LDE	DATE	REPRESENTS GENERAL DESIGN CONCEPTS BASED ON ASSUMPTIONS. REVIEWED NOT CHECKED.
APPROVED STATUS LDE	DATE	REPRESENTS REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.

ORIGINATING PERSONNEL	PROFESSIONAL ENGINEER'S SEAL
DRAWN BY	
CHECKED BY	
LEAD DESIGNER	
ENGINEER/TECH SPECIALIST	
PROJECT ENGINEERING MANAGER	
PROJECT MANAGER	ORIGINALLY PREPARED UNDER THE RESPONSIBLE SUPERVISION OF PE:____________ STATE:________ LIC. NO.:__________ DATE:________

WorleyParsons
resources & energy

	PROJECT MANAGER
	PROJ ENGR MANAGER
	LEAD DISC ENGINEER
	ENGINEER/ TECH. SPEC.
	LEAD DESIGNER
	CHECKED
	DRAWN
	DATE
	REV

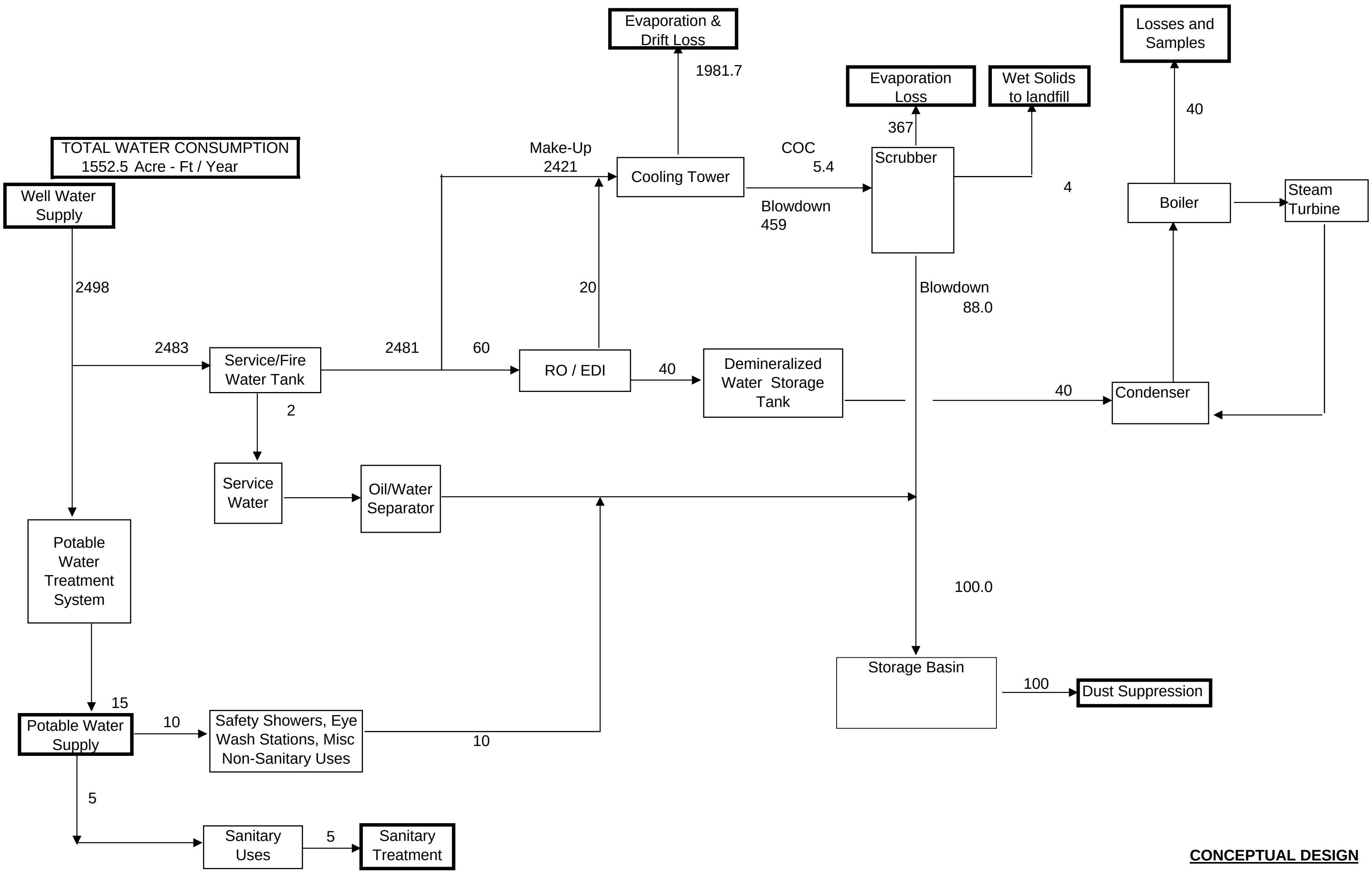
NEVADA POWER / SIERRA PACIFIC
VALMY STATION
SUPERCRITICAL PC OPTION - 50 DEG F

SCALE NONE | DRAWING SIZE D (24" x 36")

WORLEYPARSONS DWG. NO. NPSP-1-SK-ME-306-2159 | REV A

FAC	PIPING	I & C	ELECT	MECH	CIVIL	STRUC

DWG-FILE: swslarchD3d.fil
DWG-DATE: 23-Nov-05 10:44



CONCEPTUAL DESIGN

Notes:
1. Ambient conditions are degrees 68F and 50% R.H.
2. Cooling Tower blowdown is controlled to provide make-up to scrubber, and is not based on COC.
3. Scrubber blowdown is more than typical in order to provide sufficient dust supression water.
4. Losses and Samples estimated at 40 GPM total, or 1/2% feedwater flow.
5. Cooling Tower COC and scrubber blowdown chlorides are computed for comparison purposes only.

Summary Balance:

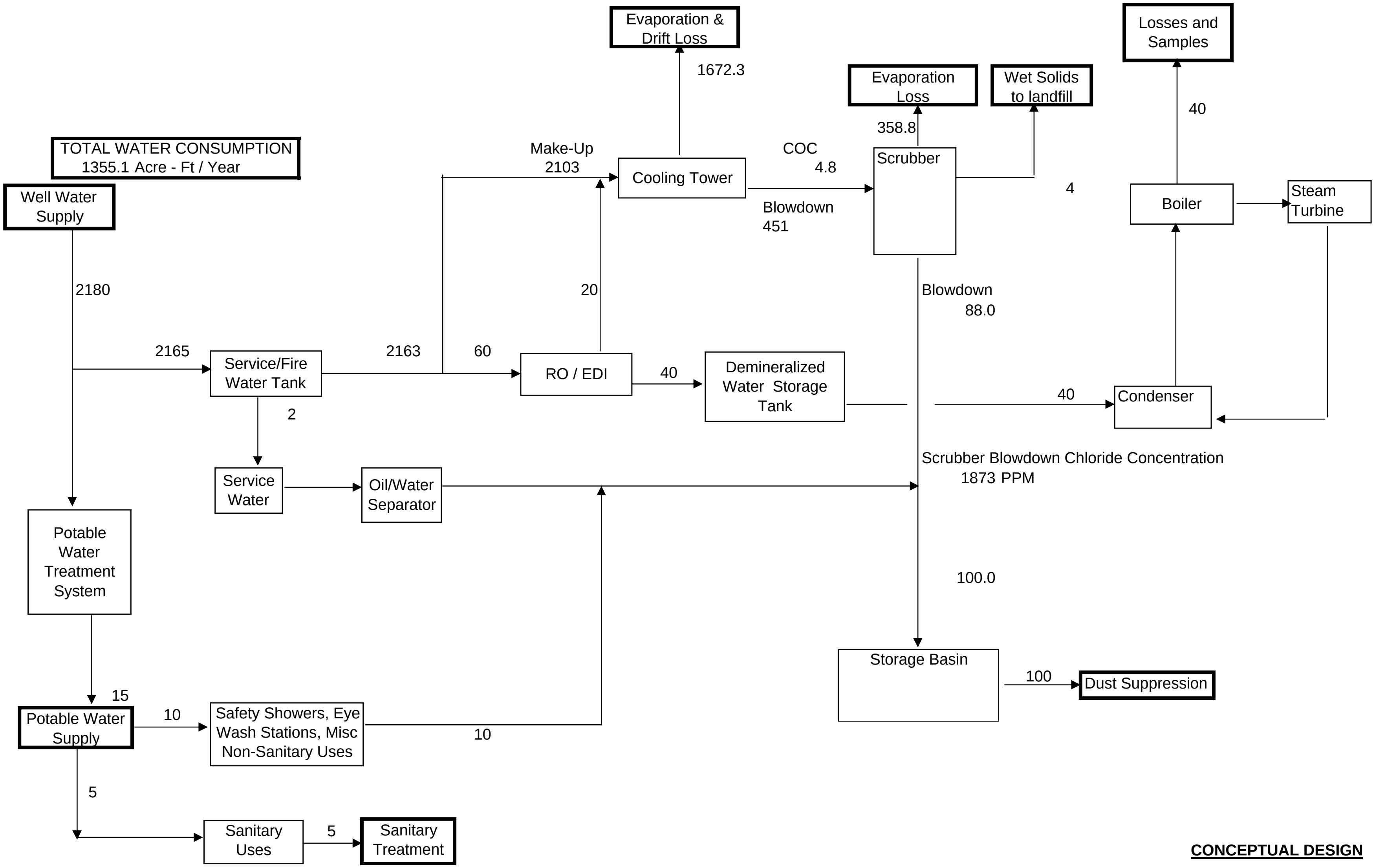
In Flow	2498
Out Flow	2498
Difference	0

Units: All flows are in GPM

Nevada Power - Reid Gardner Site

Preliminary Water Balance
Supercritical Rankine Cycle, Pulverized Coal
68 Degrees / 50% R.H.

DWG No:	Rev	Date:
NPSP-2-305-2159	A	3/10/2006



CONCEPTUAL DESIGN

Notes:
1. Ambient conditions are degrees 50F and 50% R.H.
2. Cooling Tower blowdown is controlled to provide make-up to scrubber, and is not based on COC
3. Scrubber blowdown is more than typical in order to provide sufficient dust supression water.
4. Losses and Samples estimated at 40 GPM total, or 1/2% feedwater flow.
5. Cooling Tower COC and scrubber blowdown chlorides are computed for comparison purposes only

Summary Balance:

In Flow	2180
Out Flow	2180
Difference	0

Units: All flows are in GPM

Nevada Power - Valmy Site

Preliminary Water Balance
Supercritical Rankine Cycle, Pulverized Coal
50 Degrees / 50% R.H.

DWG No:	Rev	Date:
NPSP-1-305-2159	A	3/10/2006

This page is intentionally left blank

Appendix C Capital and Operating Cost Details

Nevada Power
Valmy & Reid Gardner - PC & IGCC Option Evaluations
Capital and O&M Cost Basis

ITEM	Unit	Study Values	Notes
CAPITAL COST			
Cost Base	year	2006	January
Construction Labor			Union labor, Reno & Las Vegas regions
Labor Contract Basis			Multiple major contract packages
Labor Indirect Cost	%	7.0	% of direct labor for costs not included in the construction contract scope
Estimate Scope			Battery Limits, receipt of coal & limestone to high side of main power transformer
Fuel Basis			Black Butte PRB blend
Professional Services	%	10.0	Allowance for Engineering, CM and start-up assistance (% of Bare Erected Cost)
Process Contingency	%	10.0	% rate applied to E-Gas package
Project Contingency	%	varies	Rates of 5% to 30% assigned, depending on potential for change of that estimate item
OPERATING & MAINTENANCE COST			
Operator Average Rate	$/hr.	38.60	base rate
Indirect Costs	%	30	overheads and burdens
Administrative & Support Labor	%	25	% of Operation & Maintenance Labor $
Maintenance (average annual expense)	%	varies	Rates of 0.5% to 5.0% of installed equipment cost assigned to components/systems. Higher rates assigned to gasifiers & combustion turbines.
Maintenance Material / Labor	% ratio	60/40	Total maintenance typical ratio of material (variable) and labor (fixed) components (labor adjusted to be consistent w/ local rates)
Plant equivalent 100% Load Capacity Factor	%	85.0	
On-Line Auxiliary Power	$/MWh		Aux power recognized in the plant heat rate
Water	$/1000 gal	0.00	Available at site, no cost included
Steam	$/1000#		Steam recognized in the plant heat rate
Water Treating Chemicals	$/lb.	0.22	Composite average cost of chemicals
Waste Water Treating Chemicals	$/1000 gal		Waste water sent to on-site evaporation ponds
Limestone	$/ton	20.00	
Aqueous Ammonia	$/ton	200.00	
SCR Catalyst Replacement	$/m^3	4,800.00	
Carbon (mercury removal)	$/lb.	9.84	
COS Catalyst	$/lb.	0.91	
Selexol Solution	$/gal	12.00	
Spent Carbon	$/lb.	0.38	
Waste Ash Disposal	$/ton	5.00	On-Site
Gypsum Disposal	$/ton	5.00	On-Site
SCR Catalyst Disposal Charge	$/m^3		Excluded
Sulfur Allowances	$/ton	0.00	Value of Sulfur not included

Client: Nevada Power
Project: IGCC Plant Feasibility Study

Report Date: 03-May-2006
10:16 AM

TOTAL PLANT COST SUMMARY

Case: CP E-Gas IGCC - 2 (+0) w/ SCR, Reid Gardner
Plant Size: 568.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING	10,615	2,182	13,491	944		**$27,232**	2,723		5,110	**$35,065**	62
2	COAL & SORBENT PREP & FEED	17,428	8,862	16,931	1,185		**$44,407**	4,441	4,274	5,495	**$58,617**	103
3	FEEDWATER & MISC. BOP SYSTEMS	6,899	6,187	10,073	705		**$23,864**	2,386		5,913	**$32,163**	57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-G	53,847	25,201	51,439	3,601		**$134,088**	13,409	13,409	16,091	**$176,996**	311
4.2	Syngas Cooling	w/4.1	w/ 4.1	w/ 4.1	w/ 4.1			w/ 4.1		w/ 4.1		
4.3	ASU/Oxidant Compression	107,637		w/equip.			**$107,637**	10,764		5,920	**$124,321**	219
4.4-4.9	Other Gasification Equipment	13,190	16,670	18,633	1,304		**$49,798**	4,980	2,983	7,728	**$65,489**	115
	SUBTOTAL 4	*174,675*	*41,870*	*70,072*	*4,905*		***$291,523***	*29,152*	*16,392*	*29,739*	***$366,806***	*645*
5A	GAS CLEANUP & PIPING	33,434	1,643	49,486	3,464		**$88,027**	8,803		12,326	**$109,156**	192
5B	CO_2 REMOVAL & COMPRESSION											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	79,400		6,279	440		**$86,119**	8,612		9,473	**$104,204**	183
6.2-6.9	Combustion Turbine Accessories		568	972	68		**$1,608**	161		531	**$2,299**	4
	SUBTOTAL 6	*79,400*	*568*	*7,251*	*508*		***$87,726***	*8,773*		*10,004*	***$106,503***	*187*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	28,905		5,893	413		**$35,211**	3,521		3,873	**$42,605**	75
7.2-7.9	SCR System, Ductwork and Stack	2,641	4,389	6,198	434		**$13,662**	1,366		3,087	**$18,115**	32
	SUBTOTAL 7	*31,546*	*4,389*	*12,091*	*846*		***$48,872***	*4,887*		*6,960*	***$60,720***	*107*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	25,957		6,070	425		**$32,452**	3,245		2,677	**$38,375**	67
8.2-8.9	Turbine Plant Auxiliaries and Steam Pipin	5,995	783	8,115	568		**$15,460**	1,546		2,891	**$19,898**	35
	SUBTOTAL 8	*31,952*	*783*	*14,185*	*993*		***$47,913***	*4,791*		*5,569*	***$58,272***	*102*
9	COOLING WATER SYSTEM	6,822	5,966	13,090	916		**$26,794**	2,679		4,506	**$33,980**	60
10	ASH/SPENT SORBENT HANDLING SYS	14,461	7,010	12,945	906		**$35,321**	3,532	3,089	4,444	**$46,386**	82
11	ACCESSORY ELECTRIC PLANT	14,676	6,710	25,797	1,806		**$48,988**	4,899		8,998	**$62,885**	111
12	INSTRUMENTATION & CONTROL	6,208	938	7,151	501		**$14,798**	1,480		2,387	**$18,664**	33
13	IMPROVEMENTS TO SITE	2,875	1,694	9,764	684		**$15,017**	1,502		4,130	**$20,648**	36
14	BUILDINGS & STRUCTURES		4,015	7,166	502		**$11,683**	1,168		2,570	**$15,422**	27
	TOTAL COST	**$430,989**	**$92,818**	**$269,494**	**$18,865**		**$812,165**	**$81,217**	**$23,755**	**$108,150**	**$1,025,287**	**1803**

Client: Nevada Power
Project: IGCC Plant Feasibility Study

Report Date: 03-May-2006
10:16 AM

TOTAL PLANT COST SUMMARY

Case: CP E-Gas IGCC - 2 (+0) w/ SCR, Reid Gardner
Plant Size: 568.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,238		1,747	122		$4,106	411		678	$5,195	9
1.2	Coal Stackout & Reclaim	3,855		1,493	105		$5,453	545		900	$6,898	12
1.3	Coal Conveyors & Yd Crush	3,584		1,477	103		$5,165	516		852	$6,534	11
1.4	Other Coal Handling	938		342	24		$1,303	130		215	$1,649	3
1.5	Sorbent Receive & Unload											
1.6	Sorbent Stackout & Reclaim											
1.7	Sorbent Conveyors											
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations		2,182	8,433	590		$11,205	1,120		2,465	$14,790	26
	SUBTOTAL 1.	**$10,615**	**$2,182**	**$13,491**	**$944**		**$27,232**	**$2,723**		**$5,110**	**$35,065**	**62**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying											
2.2	Prepared Coal Storage & Feed											
2.3	Slurry Prep & Feed	17,428	8,157	16,036	1,122		$42,743	4,274	4,274	5,129	$56,421	99
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment											
2.6	Sorbent Storage & Feed											
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		706	895	63		$1,663	166		366	$2,196	4
	SUBTOTAL 2.	**$17,428**	**$8,862**	**$16,931**	**$1,185**		**$44,407**	**$4,441**	**$4,274**	**$5,495**	**$58,617**	**103**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	2,191	4,261	3,226	226		$9,904	990		2,179	$13,073	23
3.2	Water Makeup (Wells) & Pretreatment	772	82	628	44		$1,526	153		504	$2,183	4
3.3	Other Feedwater Subsystems	1,228	459	592	41		$2,320	232		510	$3,063	5
3.4	Service Water Systems	103	220	1,096	77		$1,496	150		494	$2,139	4
3.5	Other Boiler Plant Systems	1,631	659	2,340	164		$4,794	479		1,055	$6,328	11
3.6	FO Supply Sys & Nat Gas	65	311	416	29		$821	82		181	$1,084	2
3.7	Liquid Waste Evaporation Ponds & Piping	20	75	1,125	79		$1,299	130		429	$1,857	3
3.8	Misc. Power Plant Equipment	888	120	650	45		$1,704	170		562	$2,436	4
	SUBTOTAL 3.	**$6,899**	**$6,187**	**$10,073**	**$705**		**$23,864**	**$2,386**		**$5,913**	**$32,163**	**57**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-G	53,847	25,201	51,439	3,601		$134,088	13,409	13,409	16,091	$176,996	311
4.2	Syngas Cooling	w/4.1	w/ 4.1	w/ 4.1	w/ 4.1			w/ 4.1		w/ 4.1		
4.3	ASU/Oxidant Compression	107,637		w/equip.			$107,637	10,764		5,920	$124,321	219
4.4	LT Heat Recovery & FG Saturation	13,190	6,173	9,783	685		$29,831	2,983	2,983	3,580	$39,377	69
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment		1,366	797	56		$2,220	222		244	$2,686	5
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations		9,131	8,053	564		$17,747	1,775		3,904	$23,426	41
	SUBTOTAL 4.	**$174,675**	**$41,870**	**$70,072**	**$4,905**		**$291,523**	**$29,152**	**$16,392**	**$29,739**	**$366,806**	**645**

Client: Nevada Power **Report Date:** 03-May-2006
Project: IGCC Plant Feasibility Study 10:16 AM

TOTAL PLANT COST SUMMARY

Case: CP E-Gas IGCC - 2 (+0) w/ SCR, Reid Gardner
Plant Size: 568.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
5A	GAS CLEANUP & PIPING											
5A.1	Single Stage Selexol	25,500		37,333	2,613		$65,446	6,545		7,199	$79,189	139
5A.2	Elemental Sulfur Plant	2,566		4,754	333		$7,653	765		1,684	$10,102	18
5A.3	Mercury Removal	1,389		1,040	73		$2,502	250		550	$3,303	6
5A.4	COS Hydrolysis	2,517		4,713	330		$7,559	756		1,663	$9,978	18
5A.5	Blowback Gas Systems	1,462	246	199	14		$1,921	192		423	$2,535	4
5A.6	Fuel Gas Piping		696	749	52		$1,497	150		329	$1,977	3
5A.9	HGCU Foundations		701	699	49		$1,449	145		478	$2,072	4
	SUBTOTAL 5A.	**$33,434**	**$1,643**	**$49,486**	**$3,464**		**$88,027**	**$8,803**		**$12,326**	**$109,156**	**192**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System											
5B.2	CO_2 Compression & Drying											
	SUBTOTAL 5B											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	79,400		6,279	440		$86,119	8,612		9,473	$104,204	183
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		568	972	68		$1,608	161		531	$2,299	4
	SUBTOTAL 6.	**$79,400**	**$568**	**$7,251**	**$508**		**$87,726**	**$8,773**		**$10,004**	**$106,503**	**187**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	28,905		5,893	413		$35,211	3,521		3,873	$42,605	75
7.2	SCR System	2,641	555	1,221	85		$4,502	450		743	$5,695	10
7.3	Ductwork		2,679	3,261	228		$6,168	617		1,357	$8,141	14
7.4	Stack											
7.9	HRSG,Duct & Stack Foundations		1,156	1,716	120		$2,992	299		987	$4,278	8
	SUBTOTAL 7.	**$31,546**	**$4,389**	**$12,091**	**$846**		**$48,872**	**$4,887**		**$6,960**	**$60,720**	**107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	25,957		6,070	425		$32,452	3,245		2,677	$38,375	67
8.2	Turbine Plant Auxiliaries	171		563	39		$773	77		64	$915	2
8.3	Condenser & Auxiliaries	2,067		812	57		$2,936	294		242	$3,471	6
8.4	Steam Piping	3,756		4,682	328		$8,765	877		1,928	$11,570	20
8.9	TG Foundations		783	2,059	144		$2,986	299		657	$3,941	7
	SUBTOTAL 8.	**$31,952**	**$783**	**$14,185**	**$993**		**$47,913**	**$4,791**		**$5,569**	**$58,272**	**102**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	5,401		5,476	383		$11,260	1,126		1,239	$13,625	24
9.2	Circulating Water Pumps	841		114	8		$964	96		79	$1,139	2
9.3	Circ.Water System Auxiliaries	103		21	1		$125	13		10	$148	0
9.4	Circ.Water Piping		3,989	3,182	223		$7,394	739		1,627	$9,760	17
9.5	Make-up Water System (w/ 3.2)											
9.6	Component Cooling Water Sys	477	571	601	42		$1,692	169		372	$2,233	4
9.9	Circ.Water System Foundations		1,406	3,695	259		$5,359	536		1,179	$7,075	12
	SUBTOTAL 9.	**$6,822**	**$5,966**	**$13,090**	**$916**		**$26,794**	**$2,679**		**$4,506**	**$33,980**	**60**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	12,613	5,903	11,563	809		$30,888	3,089	3,089	3,707	$40,772	72
10.2	Gasifier Ash Depressurization											
10.3	Cleanup Ash Depressurization											
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	422		659	46		$1,128	113		186	$1,427	3
10.7	Ash Transport & Feed Equipment	551		196	14		$760	76		125	$962	2
10.8	Misc. Ash Handling Equipment	875	1,072	459	32		$2,439	244		402	$3,085	5
10.9	Ash/Spent Sorbent Foundation		35	67	5		$107	11		23	$141	0
	SUBTOTAL 10.	**$14,461**	**$7,010**	**$12,945**	**$906**		**$35,321**	**$3,532**	**$3,089**	**$4,444**	**$46,386**	**82**

Client: Nevada Power
Project: IGCC Plant Feasibility Study

Report Date: 03-May-2006
10:16 AM

TOTAL PLANT COST SUMMARY

Case: CP E-Gas IGCC - 2 (+0) w/ SCR, Reid Gardner
Plant Size: 568.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	779		1,111	78		$1,967	197		216	$2,381	4
11.2	Station Service Equipment	3,330		433	30		$3,793	379		417	$4,590	8
11.3	Switchgear & Motor Control	6,156		1,617	113		$7,886	789		1,301	$9,976	18
11.4	Conduit & Cable Tray		2,751	13,623	954		$17,327	1,733		3,812	$22,872	40
11.5	Wire & Cable		3,289	5,184	363		$8,836	884		1,944	$11,663	21
11.6	Protective Equipment		553	2,904	203		$3,659	366		604	$4,629	8
11.7	Standby Equipment	193		272	19		$484	48		80	$612	1
11.8	Main Power Transformers	4,218		170	12		$4,400	440		484	$5,324	9
11.9	Electrical Foundations		118	484	34		$636	64		140	$839	1
	SUBTOTAL 11.	**$14,676**	**$6,710**	**$25,797**	**$1,806**		**$48,988**	**$4,899**		**$8,998**	**$62,885**	**111**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	643		620	43		$1,307	131		216	$1,654	3
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	192		178	12		$383	38		84	$505	1
12.7	Computer & Accessories	3,077		142	10		$3,230	323		355	$3,908	7
12.8	Instrument Wiring & Tubing		938	4,602	322		$5,862	586		1,290	$7,738	14
12.9	Other I & C Equipment	2,294		1,609	113		$4,016	402		442	$4,859	9
	SUBTOTAL 12.	**$6,208**	**$938**	**$7,151**	**$501**		**$14,798**	**$1,480**		**$2,387**	**$18,664**	**33**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		90	2,654	186		$2,930	293		806	$4,028	7
13.2	Site Improvements		1,604	2,935	205		$4,744	474		1,305	$6,523	11
13.3	Site Facilities	2,875		4,176	292		$7,343	734		2,019	$10,096	18
	SUBTOTAL 13.	**$2,875**	**$1,694**	**$9,764**	**$684**		**$15,017**	**$1,502**		**$4,130**	**$20,648**	**36**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		168	157	11		$337	34		74	$444	1
14.2	Steam Turbine Building		1,803	4,240	297		$6,341	634		1,395	$8,370	15
14.3	Administration Building		611	732	51		$1,395	139		307	$1,841	3
14.4	Circulation Water Pumphouse		120	105	7		$233	23		51	$308	1
14.5	Water Treatment Buildings		404	650	46		$1,100	110		242	$1,452	3
14.6	Machine Shop		313	353	25		$691	69		152	$912	2
14.7	Warehouse		293	538	38		$869	87		191	$1,147	2
14.8	Other Buildings & Structures		303	389	27		$719	72		158	$949	2
14.9	Waste Treating Building & Str.											
	SUBTOTAL 14.		**$4,015**	**$7,166**	**$502**		**$11,683**	**$1,168**		**$2,570**	**$15,422**	**27**
	TOTAL COST	**$430,989**	**$92,818**	**$269,494**	**$18,865**		**$812,165**	**$81,217**	**$23,755**	**$108,150**	**$1,025,287**	**1803**

INITIAL & ANNUAL O&M EXPENSES

CP E-Gas IGCC - 2 (+0) w/ SCR, Reid Gardner

Cost Base (Jan.)	2006
Heat Rate-net(Btu/kWh):	8700
MWe-net:	568.72
Capacity Factor: (%):	85

Plant Output: Carbon Dioxide (tpd) Hydrogen (mmscfd)

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	43.20	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	10.3	10.3
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	15.3	15.3

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$7,543,247	13.26
Maintenance Labor Cost	$9,709,735	17.07
Administrative & Support Labor	$4,313,246	7.58
TOTAL FIXED OPERATING COSTS	**$21,566,228**	**37.92**

VARIABLE OPERATING COSTS

	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost $	$/kWh-net
Maintenance Material Cost					$18,293,184	0.00432
Consumables						
Water(/1000 gallons)		2,161				
Chemicals						
MU & WT Chem.(lbs)	45,064	6,438	0.22	$9,965	$441,662	0.00010
Carbon (Mercury Removal) (lb.)	922	131.8	9.84	$9,081	$402,499	0.00010
COS Catalyst (lb)	4,789	684.2	0.91	$4,352	$192,890	0.00005
Selexol Solution (gal.)	559	79.8	12.00	$6,703	$297,071	0.00007
SCR Catalyst (m^3)	w/Equipment	54.3	4800.00		$260,538	0.00006
Aqueous Ammonia (ton)	20	2.9	200.00	$4,024	$178,357	0.00004
Subtotal-Chemicals				$34,125	$1,773,016	0.00042
Other						
Supplemental Fuel(MBtu)						
Gases,N2 etc.(/100scf)						
Subtotal Other						
Subtotal-Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		132	0.38		$15,481	0.00000
Flyash (ton)						
Bottom Ash(ton)		942	5.00		$1,460,756	0.00034
Subtotal-Waste Disposal					$1,476,237	0.00035
By-products & Emissions						
Sulfur(tons)		28				
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS					**$21,542,436**	**0.00509**

Client:	Nevada Power		**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study			10:07 AM

TOTAL PLANT COST SUMMARY

Case:	CP E-Gas IGCC - 2 (+1) w/ SCR, Valmy				
Plant Size:	541.6 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan.)**	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	10,213	2,099	11,612	813		**$24,737**	2,474		4,624	**$31,835**	59
2	COAL & SORBENT PREP & FEED	18,755	9,454	16,619	1,163		**$45,992**	4,599	4,449	5,669	**$60,709**	112
3	FEEDWATER & MISC. BOP SYSTEMS	6,548	5,870	7,947	556		**$20,922**	2,092		5,125	**$28,139**	52
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-G	74,527	34,879	65,350	4,574		**$179,330**	17,933	17,933	21,520	**$236,715**	437
4.2	Syngas Cooling	w/4.1	w/ 4.1	w/ 4.1	w/ 4.1			w/ 4.1		w/ 4.1		
4.3	ASU/Oxidant Compression	101,468		w/equip.			**$101,468**	10,147		5,581	**$117,196**	216
4.4-4.9	Other Gasification Equipment	12,627	16,126	16,353	1,145		**$46,251**	4,625	2,780	7,161	**$60,817**	112
	SUBTOTAL 4	*188,622*	*51,005*	*81,703*	*5,719*		***$327,049***	*32,705*	*20,713*	*34,261*	***$414,728***	*766*
5A	GAS CLEANUP & PIPING	31,933	1,575	42,206	2,954		**$78,668**	7,867		11,034	**$97,569**	180
5B	CO_2 REMOVAL & COMPRESSION											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	79,400		5,617	393		**$85,410**	8,541		9,395	**$103,346**	191
6.2-6.9	Combustion Turbine Accessories		568	869	61		**$1,498**	150		494	**$2,142**	4
	SUBTOTAL 6	*79,400*	*568*	*6,486*	*454*		***$86,908***	*8,691*		*9,889*	***$105,488***	*195*
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	27,636		5,040	353		**$33,030**	3,303		3,633	**$39,966**	74
7.2-7.9	SCR System, Ductwork and Stack	2,323	4,154	5,218	365		**$12,060**	1,206		2,736	**$16,002**	30
	SUBTOTAL 7	*29,959*	*4,154*	*10,258*	*718*		***$45,089***	*4,509*		*6,370*	***$55,968***	*103*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	25,097		5,250	368		**$30,715**	3,071		2,534	**$36,320**	67
8.2-8.9	Turbine Plant Auxiliaries and Steam Pipin	5,813	759	7,039	493		**$14,104**	1,410		2,629	**$18,144**	34
	SUBTOTAL 8	*30,910*	*759*	*12,289*	*860*		***$44,819***	*4,482*		*5,163*	***$54,464***	*101*
9	COOLING WATER SYSTEM	6,621	5,790	11,366	796		**$24,573**	2,457		4,126	**$31,156**	58
10	ASH/SPENT SORBENT HANDLING SYS	19,193	9,216	15,855	1,110		**$45,374**	4,537	4,124	5,636	**$59,672**	110
11	ACCESSORY ELECTRIC PLANT	14,212	6,503	22,363	1,565		**$44,643**	4,464		8,148	**$57,255**	106
12	INSTRUMENTATION & CONTROL	6,113	924	6,300	441		**$13,777**	1,378		2,201	**$17,356**	32
13	IMPROVEMENTS TO SITE	2,806	1,654	8,525	597		**$13,581**	1,358		3,735	**$18,674**	34
14	BUILDINGS & STRUCTURES		3,899	6,220	435		**$10,554**	1,055		2,322	**$13,931**	26
	TOTAL COST	**$445,283**	**$103,470**	**$259,749**	**$18,182**		**$826,685**	**$82,669**	**$29,286**	**$108,303**	**$1,046,943**	**1933**

	Client:	Nevada Power							**Report Date:**	03-May-2006		
	Project:	IGCC Plant Feasibility Study								10:07 AM		

TOTAL PLANT COST SUMMARY

	Case:	CP E-Gas IGCC - 2 (+1) w/ SCR, Valmy										
	Plant Size:	541.6 MW,net		**Estimate Type:**	Conceptual			**Cost Base (Jan.)**	2006	($x1000)		

Acct		**Equipment**	**Material**	**Labor**		**Sales**	**Bare Erected**	**Eng'g CM**	**Contingencies**		**TOTAL PLANT COST**	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,153		1,503	105		$3,761	376		621	$4,758	9
1.2	Coal Stackout & Reclaim	3,709		1,285	90		$5,084	508		839	$6,431	12
1.3	Coal Conveyors & Yd Crush	3,449		1,271	89		$4,809	481		793	$6,083	11
1.4	Other Coal Handling	902		294	21		$1,217	122		201	$1,540	3
1.5	Sorbent Receive & Unload											
1.6	Sorbent Stackout & Reclaim											
1.7	Sorbent Conveyors											
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations		2,099	7,258	508		$9,865	987		2,170	$13,022	24
	SUBTOTAL 1.	**$10,213**	**$2,099**	**$11,612**	**$813**		**$24,737**	**$2,474**		**$4,624**	**$31,835**	**59**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying											
2.2	Prepared Coal Storage & Feed											
2.3	Slurry Prep & Feed	18,755	8,777	15,851	1,110		$44,492	4,449	4,449	5,339	$58,730	108
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment											
2.6	Sorbent Storage & Feed											
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		677	769	54		$1,500	150		330	$1,979	4
	SUBTOTAL 2.	**$18,755**	**$9,454**	**$16,619**	**$1,163**		**$45,992**	**$4,599**	**$4,449**	**$5,669**	**$60,709**	**112**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	2,099	4,083	2,764	194		$9,140	914		2,011	$12,065	22
3.2	Water Makeup (Wells) & Pretreatment	687	73	500	35		$1,295	130		427	$1,852	3
3.3	Other Feedwater Subsystems	1,177	440	507	36		$2,159	216		475	$2,850	5
3.4	Service Water Systems	92	196	872	61		$1,221	122		403	$1,746	3
3.5	Other Boiler Plant Systems	1,452	586	1,863	130		$4,031	403		887	$5,320	10
3.6	FO Supply Sys & Nat Gas	160	302	361	25		$848	85		187	$1,120	2
3.7	Liquid Waste Evaporation Ponds & Piping	20	75	515	36		$646	65		213	$924	2
3.8	Misc. Power Plant Equipment	862	117	564	39		$1,582	158		522	$2,262	4
	SUBTOTAL 3.	**$6,548**	**$5,870**	**$7,947**	**$556**		**$20,922**	**$2,092**		**$5,125**	**$28,139**	**52**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-G	74,527	34,879	65,350	4,574		$179,330	17,933	17,933	21,520	$236,715	437
4.2	Syngas Cooling	w/4.1	w/ 4.1	w/ 4.1	w/ 4.1			w/ 4.1		w/ 4.1		
4.3	ASU/Oxidant Compression	101,468		w/equip.			$101,468	10,147		5,581	$117,196	216
4.4	LT Heat Recovery & FG Saturation	12,627	5,909	8,657	606		$27,799	2,780	2,780	3,336	$36,695	68
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment		1,366	713	50		$2,130	213		234	$2,577	5
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations		8,851	6,983	489		$16,322	1,632		3,591	$21,545	40
	SUBTOTAL 4.	**$188,622**	**$51,005**	**$81,703**	**$5,719**		**$327,049**	**$32,705**	**$20,713**	**$34,261**	**$414,728**	**766**

Client:	Nevada Power								**Report Date:**	03-May-2006	
Project:	IGCC Plant Feasibility Study									10:07 AM	

TOTAL PLANT COST SUMMARY

Case: CP E-Gas IGCC - 2 (+1) w/ SCR, Valmy

Plant Size: 541.6 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Single Stage Selexol	24,289		31,810	2,227		$58,326	5,833		6,416	$70,575	130
5A.2	Elemental Sulfur Plant	2,462		4,079	286		$6,827	683		1,502	$9,011	17
5A.3	Mercury Removal	1,322		891	62		$2,275	228		501	$3,003	6
5A.4	COS Hydrolysis	2,397		4,015	281		$6,694	669		1,473	$8,836	16
5A.5	Blowback Gas Systems	1,462	246	178	12		$1,898	190		418	$2,506	5
5A.6	Fuel Gas Piping		662	638	45		$1,344	134		296	$1,774	3
5A.9	HGCU Foundations		667	595	42		$1,303	130		430	$1,864	3
	SUBTOTAL 5A.	**$31,933**	**$1,575**	**$42,206**	**$2,954**		**$78,668**	**$7,867**		**$11,034**	**$97,569**	**180**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System											
5B.2	CO_2 Compression & Drying											
	SUBTOTAL 5B											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	79,400		5,617	393		$85,410	8,541		9,395	$103,346	191
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		568	869	61		$1,498	150		494	$2,142	4
	SUBTOTAL 6.	**$79,400**	**$568**	**$6,486**	**$454**		**$86,908**	**$8,691**		**$9,889**	**$105,488**	**195**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	27,636		5,040	353		$33,030	3,303		3,633	$39,966	74
7.2	SCR System	2,323	488	961	67		$3,839	384		633	$4,856	9
7.3	Ductwork		2,561	2,789	195		$5,545	555		1,220	$7,320	14
7.4	Stack											
7.9	HRSG,Duct & Stack Foundations		1,105	1,467	103		$2,675	268		883	$3,826	7
	SUBTOTAL 7.	**$29,959**	**$4,154**	**$10,258**	**$718**		**$45,089**	**$4,509**		**$6,370**	**$55,968**	**103**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	25,097		5,250	368		$30,715	3,071		2,534	$36,320	67
8.2	Turbine Plant Auxiliaries	166		488	34		$688	69		57	$814	2
8.3	Condenser & Auxiliaries	2,004		704	49		$2,758	276		228	$3,261	6
8.4	Steam Piping	3,643		4,061	284		$7,988	799		1,757	$10,544	19
8.9	TG Foundations		759	1,786	125		$2,670	267		587	$3,524	7
	SUBTOTAL 8.	**$30,910**	**$759**	**$12,289**	**$860**		**$44,819**	**$4,482**		**$5,163**	**$54,464**	**101**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	5,244		4,756	333		$10,333	1,033		1,137	$12,503	23
9.2	Circulating Water Pumps	817		99	7		$923	92		76	$1,092	2
9.3	Circ.Water System Auxiliaries	100		18	1		$119	12		10	$141	0
9.4	Circ.Water Piping		3,873	2,764	193		$6,831	683		1,503	$9,017	17
9.5	Make-up Water System (w/ 3.2)											
9.6	Component Cooling Water Sys	461	551	519	36		$1,568	157		345	$2,069	4
9.9	Circ.Water System Foundations		1,365	3,209	225		$4,799	480		1,056	$6,335	12
	SUBTOTAL 9.	**$6,621**	**$5,790**	**$11,366**	**$796**		**$24,573**	**$2,457**		**$4,126**	**$31,156**	**58**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	17,408	8,147	14,661	1,026		$41,242	4,124	4,124	4,949	$54,440	101
10.2	Gasifier Ash Depressurization											
10.3	Cleanup Ash Depressurization											
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	408		570	40		$1,017	102		168	$1,287	2
10.7	Ash Transport & Feed Equipment	532		169	12		$713	71		118	$902	2
10.8	Misc. Ash Handling Equipment	845	1,036	397	28		$2,306	231		380	$2,917	5
10.9	Ash/Spent Sorbent Foundation		33	58	4		$96	10		21	$126	0
	SUBTOTAL 10.	**$19,193**	**$9,216**	**$15,855**	**$1,110**		**$45,374**	**$4,537**	**$4,124**	**$5,636**	**$59,672**	**110**

Client:	Nevada Power	**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study		10:07 AM

TOTAL PLANT COST SUMMARY

Case:	CP E-Gas IGCC - 2 (+1) w/ SCR, Valmy		
Plant Size:	541.6 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan.)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	756		965	68		$1,788	179		197	$2,163	4
11.2	Station Service Equipment	3,229		376	26		$3,631	363		399	$4,393	8
11.3	Switchgear & Motor Control	5,969		1,402	98		$7,470	747		1,232	$9,449	17
11.4	Conduit & Cable Tray		2,667	11,816	827		$15,310	1,531		3,368	$20,210	37
11.5	Wire & Cable		3,189	4,497	315		$8,000	800		1,760	$10,560	19
11.6	Protective Equipment		533	2,506	175		$3,215	321		530	$4,067	8
11.7	Standby Equipment	188		237	17		$442	44		73	$559	1
11.8	Main Power Transformers	4,070		146	10		$4,227	423		465	$5,114	9
11.9	Electrical Foundations		114	417	29		$561	56		123	$740	1
	SUBTOTAL 11.	**$14,212**	**$6,503**	**$22,363**	**$1,565**		**$44,643**	**$4,464**		**$8,148**	**$57,255**	**106**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	634		547	38		$1,218	122		201	$1,541	3
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	189		157	11		$357	36		79	$471	1
12.7	Computer & Accessories	3,030		125	9		$3,165	316		348	$3,829	7
12.8	Instrument Wiring & Tubing		924	4,054	284		$5,261	526		1,158	$6,945	13
12.9	Other I & C Equipment	2,259		1,417	99		$3,776	378		415	$4,569	8
	SUBTOTAL 12.	**$6,113**	**$924**	**$6,300**	**$441**		**$13,777**	**$1,378**		**$2,201**	**$17,356**	**32**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		88	2,317	162		$2,567	257		706	$3,530	7
13.2	Site Improvements		1,566	2,562	179		$4,307	431		1,184	$5,922	11
13.3	Site Facilities	2,806		3,646	255		$6,707	671		1,844	$9,222	17
	SUBTOTAL 13.	**$2,806**	**$1,654**	**$8,525**	**$597**		**$13,581**	**$1,358**		**$3,735**	**$18,674**	**34**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		168	141	10		$319	32		70	$421	1
14.2	Steam Turbine Building		1,758	3,699	259		$5,716	572		1,257	$7,545	14
14.3	Administration Building		601	644	45		$1,290	129		284	$1,703	3
14.4	Circulation Water Pumphouse		118	93	6		$218	22		48	$287	1
14.5	Water Treatment Buildings		359	518	36		$913	91		201	$1,206	2
14.6	Machine Shop		308	311	22		$640	64		141	$845	2
14.7	Warehouse		288	473	33		$794	79		175	$1,049	2
14.8	Other Buildings & Structures		298	342	24		$664	66		146	$876	2
14.9	Waste Treating Building & Str.											
	SUBTOTAL 14.		**$3,899**	**$6,220**	**$435**		**$10,554**	**$1,055**		**$2,322**	**$13,931**	**26**
	TOTAL COST	**$445,283**	**$103,470**	**$259,749**	**$18,182**		**$826,685**	**$82,669**	**$29,286**	**$108,303**	**$1,046,943**	**1933**

INITIAL & ANNUAL O&M EXPENSES

CP E-Gas IGCC - 2 (+1) w/ SCR, Valmy		Cost Base (Jan.)	2006
Plant Output: Carbon Dioxide (tpd)	Hydrogen (mmscfd)	Heat Rate-net(Btu/kWh):	8585
		MWe-net:	541.56
		Capacity Factor: (%):	85

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	38.60	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant	Annual Cost $	Annual Unit Cost $/kW-net
Skilled Operator	2.0	2.0		
Operator	10.3	10.3		
Foreman	1.0	1.0		
Lab Tech's, etc.	2.0	2.0		
TOTAL-O.J.'s	15.3	15.3		
Annual Operating Labor Cost			$6,740,031	12.45
Maintenance Labor Cost			$10,323,859	19.06
Administrative & Support Labor			$4,265,972	7.88
TOTAL FIXED OPERATING COSTS			**$21,329,862**	**39.39**

VARIABLE OPERATING COSTS

	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost	$/kWh-net
Maintenance Material Cost					$19,454,576	0.00482
Consumables						
Water(/1000 gallons)		1,834				
Chemicals						
MU & WT Chem.(lbs)	38,233	5,462	0.22	$8,454	$374,712	0.00009
Carbon (Mercury Removal) (lb.)	867	123.8	9.84	$8,532	$378,167	0.00009
COS Catalyst (lb)	4,500	642.8	0.91	$4,089	$181,230	0.00004
Selexol Solution (gal.)	525	75.0	12.00	$6,297	$279,113	0.00007
SCR Catalyst (m^3)	w/Equipment	50.9	4800.00		$244,356	0.00006
Aqueous Ammonia (ton)	19	2.7	200.00	$3,774	$167,279	0.00004
Subtotal-Chemicals				$31,147	$1,624,857	0.00040
Other						
Supplemental Fuel(MBtu)						
Gases,N2 etc.(/100scf)						
Subtotal Other						
Subtotal-Other						
Waste Disposal						
Spent Mercury Catalyst (lb.)		124	0.38		$14,545	0.00000
Flyash (ton)						
Bottom Ash(ton)		885	5.00		$1,372,447	0.00034
Subtotal-Waste Disposal					$1,386,992	0.00034
By-products & Emissions						
Sulfur(tons)		27				
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS					**$22,466,425**	**0.00557**

Client:	Nevada Power	**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study		10:17 AM

TOTAL PLANT COST SUMMARY

Case:	SuperCritical PC w/ Wet FGD & SCR, Reid Gardner						
Plant Size:	600.4 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan.)**	2006	($x1000)	

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	12,041	4,047	13,999			**$30,087**	3,009		5,640	**$38,736**	65
2	COAL & SORBENT PREP & FEED	7,483	156	2,841			**$10,479**	1,048		1,742	**$13,268**	22
3	FEEDWATER & MISC. BOP SYSTEMS	31,179	232	24,810			**$56,221**	5,622		8,343	**$70,186**	117
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	125,513		156,420			**$281,934**	28,193		23,260	**$333,386**	555
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/ ID Fans)											
	SUBTOTAL 4	*125,513*		*156,420*			***$281,934***	*28,193*		*23,260*	***$333,386***	*555*
5	FLUE GAS CLEANUP	68,304		37,326			**$105,631**	10,563		8,715	**$124,908**	208
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	17,042	988	19,293			**$37,322**	3,732		4,398	**$45,452**	76
	SUBTOTAL 7	*17,042*	*988*	*19,293*			***$37,322***	*3,732*		*4,398*	***$45,452***	*76*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	43,331		13,511			**$56,842**	5,684		4,690	**$67,216**	112
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	17,005	920	16,982			**$34,908**	3,491		4,706	**$43,105**	72
	SUBTOTAL 8	*60,336*	*920*	*30,494*			***$91,750***	*9,175*		*9,396*	***$110,321***	*184*
9	COOLING WATER SYSTEM	13,458	9,357	21,059			**$43,873**	4,387		7,127	**$55,387**	92
10	ASH/SPENT SORBENT HANDLING SYS	3,696	112	7,772			**$11,580**	1,158		1,929	**$14,666**	24
11	ACCESSORY ELECTRIC PLANT	11,902	4,398	26,383			**$42,684**	4,268		5,388	**$52,340**	87
12	INSTRUMENTATION & CONTROL	6,811		11,933			**$18,744**	1,874		2,023	**$22,641**	38
13	Improvements to Site	2,763	1,629	9,385			**$13,777**	1,378		3,031	**$18,186**	30
14	Buildings & Structures		14,553	23,232			**$37,785**	3,779		6,235	**$47,798**	80
	TOTAL COST	**$360,529**	**$36,391**	**$384,947**			**$781,866**	**$78,187**		**$87,224**	**$947,277**	**1578**

Client:	Nevada Power									**Report Date:**	03-May-2006 10:17 AM	
Project:	IGCC Plant Feasibility Study											

TOTAL PLANT COST SUMMARY

Case:	SuperCritical PC w/ Wet FGD & SCR, Reid Gardner											
Plant Size:	600.4 MW,net		**Estimate Type:**	Conceptual					**Cost Base (Jan.)**	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,353		1,837			$4,191	419		691	$5,301	9
1.2	Coal Stackout & Reclaim	4,055		1,570			$5,626	563		928	$7,116	12
1.3	Coal Conveyors	3,770		1,554			$5,324	532		878	$6,735	11
1.4	Other Coal Handling	986		360			$1,346	135		222	$1,703	3
1.5	Sorbent Receive & Unload	33		17			$50	5		8	$64	0
1.6	Sorbent Stackout & Reclaim	536		168			$704	70		116	$890	1
1.7	Sorbent Conveyors	191	39	80			$310	31		51	$392	1
1.8	Other Sorbent Handling	115	25	104			$244	24		40	$309	1
1.9	Coal & Sorbent Hnd.Foundations		3,983	8,310			$12,293	1,229		2,704	$16,226	27
	SUBTOTAL 1.	**$12,041**	**$4,047**	**$13,999**			**$30,087**	**$3,009**		**$5,640**	**$38,736**	**65**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	1,820		606			$2,427	243		400	$3,070	5
2.2	Coal Conveyor to Storage	4,661		1,739			$6,399	640		1,056	$8,095	13
2.3	Coal Injection System											
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment	894	36	317			$1,248	125		206	$1,578	3
2.6	Sorbent Storage & Feed	108		71			$178	18		29	$226	0
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		120	108			$227	23		50	$300	0
	SUBTOTAL 2.	**$7,483**	**$156**	**$2,841**			**$10,479**	**$1,048**		**$1,742**	**$13,268**	**22**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	15,108		8,470			$23,579	2,358		3,242	$29,179	49
3.2	Water Makeup & Pretreating	2,096		1,052			$3,148	315		693	$4,155	7
3.3	Other Feedwater Subsystems	4,733		3,393			$8,125	813		1,117	$10,055	17
3.4	Service Water Systems	358		310			$668	67		147	$881	1
3.5	Other Boiler Plant Systems	6,334		9,996			$16,330	1,633		2,245	$20,209	34
3.6	FO Supply Sys & Nat Gas	86	232	442			$760	76		104	$940	2
3.7	Waste Treatment Equipment											
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,463		1,148			$3,611	361		794	$4,766	8
	SUBTOTAL 3.	**$31,179**	**$232**	**$24,810**			**$56,221**	**$5,622**		**$8,343**	**$70,186**	**117**
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	125,513		156,420			$281,934	28,193		23,260	$333,386	555
4.2	Open											
4.3	Open											
4.4	Boiler BoP (w/ ID Fans)											
4.5	Primary Air System	w/4.1		w/4.1								
4.6	Secondary Air System	w/4.1		w/4.1								
4.8	Major Component Rigging		w/4.1	w/4.1								
4.9	PC Foundations		w/14.1	w/14.1								
	SUBTOTAL 4.	**$125,513**		**$156,420**			**$281,934**	**$28,193**		**$23,260**	**$333,386**	**555**

Client: Nevada Power
Project: IGCC Plant Feasibility Study

Report Date: 03-May-2006
10:17 AM

TOTAL PLANT COST SUMMARY

Case: SuperCritical PC w/ Wet FGD & SCR, Reid Gardner
Plant Size: 600.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	47,758		15,774			$63,533	6,353		5,241	$75,127	125
5.2	Other FGD	2,492		4,333			$6,825	683		563	$8,071	13
5.3	ESP & Accessories	15,697		15,284			$30,980	3,098		2,556	$36,634	61
5.4	Other Particulate Removal Materials	956		1,570			$2,526	253		208	$2,987	5
5.5	Gypsum Dewatering System	1,401		365			$1,767	177		146	$2,089	3
5.6	Mercury Removal System											
5.9	Open											
	SUBTOTAL 5.	**$68,304**		**$37,326**			**$105,631**	**$10,563**		**$8,715**	**$124,908**	**208**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2	Combustion Turbine Accessories	N/A		N/A								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations											
	SUBTOTAL 6.											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2	HRSG Accessories											
7.3	Ductwork	7,759		9,103			$16,862	1,686		2,319	$20,867	35
7.4	Stack	9,283		8,334			$17,616	1,762		1,453	$20,831	35
7.9	Duct & Stack Foundations		988	1,856			$2,844	284		626	$3,754	6
	SUBTOTAL 7.	**$17,042**	**$988**	**$19,293**			**$37,322**	**$3,732**		**$4,398**	**$45,452**	**76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	43,331		13,511			$56,842	5,684		4,690	$67,216	112
8.2	Turbine Plant Auxiliaries	318		1,046			$1,364	136		113	$1,613	3
8.3	Condenser & Auxiliaries	3,841		1,509			$5,349	535		441	$6,326	11
8.4	Steam Piping	12,846		12,008			$24,854	2,485		3,417	$30,757	51
8.9	TG Foundations		920	2,420			$3,341	334		735	$4,410	7
	SUBTOTAL 8.	**$60,336**	**$920**	**$30,494**			**$91,750**	**$9,175**		**$9,396**	**$110,321**	**184**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	10,759		8,868			$19,627	1,963		2,159	$23,749	40
9.2	Circulating Water Pumps	1,828		249			$2,077	208		171	$2,456	4
9.3	Circ.Water System Auxiliaries	489		100			$589	59		49	$696	1
9.4	Circ.Water Piping		7,226	5,764			$12,991	1,299		2,858	$17,148	29
9.5	Make-up Water System (w/ 3.2)											
9.6	Component Cooling Water Sys	381		480			$861	86		189	$1,136	2
9.9	Circ.Water System Foundations& Structures		2,131	5,598			$7,729	773		1,700	$10,202	17
	SUBTOTAL 9.	**$13,458**	**$9,357**	**$21,059**			**$43,873**	**$4,387**		**$7,127**	**$55,387**	**92**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A		N/A								
10.2	Cyclone Ash Letdown	N/A		N/A								
10.3	HGCU Ash Letdown	N/A		N/A								
10.4	High Temperature Ash Piping	N/A		N/A								
10.5	Other Ash Recovery Equipment	N/A		N/A								
10.6	Ash Storage Silos	507		2,397			$2,904	290		479	$3,673	6
10.7	Ash Transport & Feed Equipment	3,189		5,158			$8,347	835		1,377	$10,558	18
10.8	Misc. Ash Handling Equipment											
10.9	Ash/Spent Sorbent Foundation		112	218			$329	33		72	$435	1
	SUBTOTAL 10.	**$3,696**	**$112**	**$7,772**			**$11,580**	**$1,158**		**$1,929**	**$14,666**	**24**

Client:	Nevada Power				**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study					10:17 AM

TOTAL PLANT COST SUMMARY

Case:	SuperCritical PC w/ Wet FGD & SCR, Reid Gardner					
Plant Size:	600.4 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan.)**	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,435		360			$1,795	179		148	$2,122	4
11.2	Station Service Equipment	2,736		1,389			$4,125	412		340	$4,878	8
11.3	Switchgear & Motor Control	3,146		826			$3,972	397		437	$4,806	8
11.4	Conduit & Cable Tray		1,897	10,536			$12,433	1,243		1,710	$15,386	26
11.5	Wire & Cable		2,240	11,099			$13,339	1,334		1,834	$16,507	27
11.6	Protective Equipment	156		822			$979	98		108	$1,184	2
11.7	Standby Equipment	1,133		40			$1,173	117		129	$1,419	2
11.8	Main Power Transformers	3,296		241			$3,537	354		389	$4,280	7
11.9	Electrical Foundations		261	1,070			$1,331	133		293	$1,757	3
	SUBTOTAL 11.	**$11,902**	**$4,398**	**$26,383**			**$42,684**	**$4,268**		**$5,388**	**$52,340**	**87**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7		w/12.7								
12.2	Combustion Turbine Control	N/A		N/A								
12.3	Steam Turbine Control	w/8.1		w/8.1								
12.4	Other Major Component Control											
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	392		363			$755	76		104	$934	2
12.7	Distributed Control System Equipment	3,959		1,069			$5,028	503		415	$5,946	10
12.8	Instrument Wiring & Tubing	1,341		6,578			$7,919	792		1,089	$9,800	16
12.9	Other I & C Equipment	1,119		3,922			$5,041	504		416	$5,961	10
	SUBTOTAL 12.	**$6,811**		**$11,933**			**$18,744**	**$1,874**		**$2,023**	**$22,641**	**38**
13	Improvements to Site											
13.1	Site Preparation		87	2,551			$2,638	264		580	$3,482	6
13.2	Site Improvements		1,542	2,821			$4,363	436		960	$5,759	10
13.3	Site Facilities	2,763		4,014			$6,777	678		1,491	$8,946	15
	SUBTOTAL 13.	**$2,763**	**$1,629**	**$9,385**			**$13,777**	**$1,378**		**$3,031**	**$18,186**	**30**
14	Buildings & Structures											
14.1	Boiler Building		6,418	9,967			$16,385	1,639		2,704	$20,727	35
14.2	Turbine Building		6,469	10,648			$17,117	1,712		2,824	$21,653	36
14.3	Administration Building		449	838			$1,286	129		212	$1,627	3
14.4	Circulation Water Pumphouse		128	180			$309	31		51	$391	1
14.5	Water Treatment Buildings		352	513			$865	87		143	$1,094	2
14.6	Machine Shop		300	356			$656	66		108	$830	1
14.7	Warehouse		271	480			$751	75		124	$950	2
14.8	Other Buildings & Structures		166	250			$416	42		69	$526	1
14.9	Waste Treating Building & Str.											
	SUBTOTAL 14.		**$14,553**	**$23,232**			**$37,785**	**$3,779**		**$6,235**	**$47,798**	**80**
	TOTAL COST	**$360,529**	**$36,391**	**$384,947**			**$781,866**	**$78,187**		**$87,224**	**$947,277**	**1578**

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Jan.	2006
SuperCritical PC w/ Wet FGD & SCR, Reid Gardner						Heat Rate-net(Btu/kWh):	8941
						MWe-net:	600.42
						Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	43.20	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Total Plant				
Skilled Operator	2.0		2.0				
Operator	9.0		9.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	14.0		14.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost(calc'd)						$6,887,462	11.47
Maintenance Labor Cost(calc'd)						$10,403,068	17.33
Administrative & Support Labor(calc'd)						$4,322,633	7.20
TOTAL FIXED OPERATING COSTS						**$21,613,163**	**36.00**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost(calc'd)						$9,752,876	0.0022
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)		1,456					
Chemicals							
MU & WT Chem.(lbs)	49,323	7,046	0.22	$10,907		$483,400	0.0001
Limestone (ton)	582	83	20.00	$11,631		$515,487	0.0001
Carbon (Mercury Removal) lb	1,177	168	9.84	$11,582		$513,347	0.0001
Ammonia (28% NH3) ton	232	33	200.00	$46,351		$2,054,351	0.0005
Subtotal Chemicals				$80,471		$3,566,585	0.0008
Other							
Gypsum Disposal (tons)	8,214	137	5.00			$212,379	0.0003
SCR Catalyst Replacement						$571,206	0.0001
Spent Mercury Catalyst (lb.)		168	0.38			$19,744	0.0000
Subtotal Other						$803,329	0.0002
Waste Disposal							
Fly Ash (ton)		387	5.00			$600,781	0.0001
Bottom Ash (ton)		97	5.00			$150,204	0.0000
Subtotal Solid Waste Disposal						$750,985	0.0002
By-products & Emissions							
Gypsum (tons)							
Subtotal By-Products							
TOTAL VARIABLE OPERATING COSTS						**$14,873,775**	**0.0033**

Client:	Nevada Power						**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study							10:17 AM

TOTAL PLANT COST SUMMARY

Case:	SuperCritical PC w/ Wet FGD & SCR, Valmy							
Plant Size:	600.4	MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan.)**	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	11,782	3,986	12,319			**$28,087**	2,809		5,254	**$36,149**	60
2	COAL & SORBENT PREP & FEED	7,263	136	2,464			**$9,863**	986		1,638	**$12,487**	21
3	FEEDWATER & MISC. BOP SYSTEMS	30,616	232	21,745			**$52,592**	5,259		7,789	**$65,640**	109
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	123,848		137,790			**$261,638**	26,164		21,585	**$309,387**	515
4.2	Open											
4.3	Open											
4.4-4.9	Boiler BoP (w/ ID Fans)											
	SUBTOTAL 4	*123,848*		*137,790*			***$261,638***	*26,164*		*21,585*	***$309,387***	*515*
5	FLUE GAS CLEANUP	59,844		29,674			**$89,517**	8,952		7,385	**$105,854**	176
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2-6.9	Combustion Turbine Accessories											
	SUBTOTAL 6											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2-7.9	HRSG Accessories, Ductwork and Stack	16,783	973	16,996			**$34,751**	3,475		4,087	**$42,313**	70
	SUBTOTAL 7	*16,783*	*973*	*16,996*			***$34,751***	*3,475*		*4,087*	***$42,313***	*70*
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	43,326		12,085			**$55,411**	5,541		4,571	**$65,524**	109
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	17,003	920	15,190			**$33,113**	3,311		4,453	**$40,878**	68
	SUBTOTAL 8	*60,329*	*920*	*27,275*			***$88,524***	*8,852*		*9,025*	***$106,402***	*177*
9	COOLING WATER SYSTEM	13,456	9,356	18,836			**$41,648**	4,165		6,745	**$52,559**	88
10	ASH/SPENT SORBENT HANDLING SYS	3,651	110	6,869			**$10,631**	1,063		1,771	**$13,465**	22
11	ACCESSORY ELECTRIC PLANT	11,901	4,398	23,598			**$39,897**	3,990		5,011	**$48,898**	81
12	INSTRUMENTATION & CONTROL	6,833		10,708			**$17,541**	1,754		1,885	**$21,181**	35
13	Improvements to Site	2,763	1,628	8,395			**$12,786**	1,279		2,813	**$16,878**	28
14	Buildings & Structures		14,552	20,781			**$35,332**	3,533		5,830	**$44,695**	74
	TOTAL COST	**$349,069**	**$36,291**	**$337,449**			**$722,809**	**$72,281**		**$80,818**	**$875,908**	**1459**

Client: Nevada Power **Report Date:** 03-May-2006
10:17 AM
Project: IGCC Plant Feasibility Study

TOTAL PLANT COST SUMMARY

Case: SuperCritical PC w/ Wet FGD & SCR, Valmy
Plant Size: 600.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,322		1,622			$3,944	394		651	$4,989	8
1.2	Coal Stackout & Reclaim	4,001		1,386			$5,387	539		889	$6,815	11
1.3	Coal Conveyors	3,720		1,371			$5,092	509		840	$6,441	11
1.4	Other Coal Handling	973		317			$1,291	129		213	$1,633	3
1.5	Sorbent Receive & Unload	29		13			$42	4		7	$54	0
1.6	Sorbent Stackout & Reclaim	468		131			$599	60		99	$758	1
1.7	Sorbent Conveyors	167	34	63			$264	26		43	$333	1
1.8	Other Sorbent Handling	101	22	81			$204	20		34	$258	0
1.9	Coal & Sorbent Hnd.Foundations		3,930	7,334			$11,264	1,126		2,478	$14,869	25
	SUBTOTAL 1.	**$11,782**	**$3,986**	**$12,319**			**$28,087**	**$2,809**		**$5,254**	**$36,149**	**60**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	1,794		535			$2,329	233		384	$2,946	5
2.2	Coal Conveyor to Storage	4,594		1,533			$6,128	613		1,011	$7,752	13
2.3	Coal Injection System											
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment	780	31	248			$1,059	106		175	$1,339	2
2.6	Sorbent Storage & Feed	94		55			$149	15		25	$188	0
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		104	94			$198	20		44	$261	0
	SUBTOTAL 2.	**$7,263**	**$136**	**$2,464**			**$9,863**	**$986**		**$1,638**	**$12,487**	**21**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	14,867		7,456			$22,323	2,232		3,069	$27,625	46
3.2	Water Makeup & Pretreating	1,863		836			$2,699	270		594	$3,563	6
3.3	Other Feedwater Subsystems	4,657		2,986			$7,644	764		1,051	$9,459	16
3.4	Service Water Systems	318		246			$564	56		124	$745	1
3.5	Other Boiler Plant Systems	6,233		8,798			$15,030	1,503		2,067	$18,600	31
3.6	FO Supply Sys & Nat Gas	215	232	396			$842	84		116	$1,042	2
3.7	Waste Treatment Equipment											
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	2,463		1,026			$3,489	349		768	$4,606	8
	SUBTOTAL 3.	**$30,616**	**$232**	**$21,745**			**$52,592**	**$5,259**		**$7,789**	**$65,640**	**109**
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	123,848		137,790			$261,638	26,164		21,585	$309,387	515
4.2	Open											
4.3	Open											
4.4	Boiler BoP (w/ ID Fans)											
4.5	Primary Air System	w/4.1		w/4.1								
4.6	Secondary Air System	w/4.1		w/4.1								
4.8	Major Component Rigging		w/4.1	w/4.1								
4.9	PC Foundations		w/14.1	w/14.1								
	SUBTOTAL 4.	**$123,848**		**$137,790**			**$261,638**	**$26,164**		**$21,585**	**$309,387**	**515**

Client: Nevada Power
Project: IGCC Plant Feasibility Study

Report Date: 03-May-2006
10:17 AM

TOTAL PLANT COST SUMMARY

Case: SuperCritical PC w/ Wet FGD & SCR, Valmy
Plant Size: 600.4 MW,net **Estimate Type:** Conceptual **Cost Base (Jan.)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	41,106		12,145			$53,251	5,325		4,393	$62,969	105
5.2	Other FGD	2,145		3,336			$5,481	548		452	$6,482	11
5.3	ESP & Accessories	14,476		12,609			$27,086	2,709		2,235	$32,029	53
5.4	Other Particulate Removal Materials	882		1,295			$2,177	218		180	$2,574	4
5.5	Gypsum Dewatering System	1,235		288			$1,523	152		126	$1,801	3
5.6	Mercury Removal System											
5.9	Open											
	SUBTOTAL 5.	**$59,844**		**$29,674**			**$89,517**	**$8,952**		**$7,385**	**$105,854**	**176**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2	Combustion Turbine Accessories	N/A		N/A								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations											
	SUBTOTAL 6.											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2	HRSG Accessories											
7.3	Ductwork	7,641		8,019			$15,660	1,566		2,153	$19,380	32
7.4	Stack	9,141		7,342			$16,483	1,648		1,360	$19,491	32
7.9	Duct & Stack Foundations		973	1,635			$2,608	261		574	$3,443	6
	SUBTOTAL 7.	**$16,783**	**$973**	**$16,996**			**$34,751**	**$3,475**		**$4,087**	**$42,313**	**70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	43,326		12,085			$55,411	5,541		4,571	$65,524	109
8.2	Turbine Plant Auxiliaries	318		935			$1,254	125		103	$1,482	2
8.3	Condenser & Auxiliaries	3,840		1,349			$5,190	519		428	$6,137	10
8.4	Steam Piping	12,845		10,740			$23,585	2,358		3,243	$29,186	49
8.9	TG Foundations		920	2,165			$3,085	309		679	$4,072	7
	SUBTOTAL 8.	**$60,329**	**$920**	**$27,275**			**$88,524**	**$8,852**		**$9,025**	**$106,402**	**177**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	10,758		7,932			$18,690	1,869		2,056	$22,615	38
9.2	Circulating Water Pumps	1,828		223			$2,051	205		169	$2,425	4
9.3	Circ.Water System Auxiliaries	489		89			$578	58		48	$684	1
9.4	Circ.Water Piping		7,226	5,156			$12,381	1,238		2,724	$16,343	27
9.5	Make-up Water System (w/ 3.2)											
9.6	Component Cooling Water Sys	381		429			$810	81		178	$1,069	2
9.9	Circ.Water System Foundations& Structures		2,130	5,008			$7,138	714		1,570	$9,422	16
	SUBTOTAL 9.	**$13,456**	**$9,356**	**$18,836**			**$41,648**	**$4,165**		**$6,745**	**$52,559**	**88**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A		N/A								
10.2	Cyclone Ash Letdown	N/A		N/A								
10.3	HGCU Ash Letdown	N/A		N/A								
10.4	High Temperature Ash Piping	N/A		N/A								
10.5	Other Ash Recovery Equipment	N/A		N/A								
10.6	Ash Storage Silos	501		2,118			$2,619	262		432	$3,313	6
10.7	Ash Transport & Feed Equipment	3,150		4,558			$7,709	771		1,272	$9,752	16
10.8	Misc. Ash Handling Equipment											
10.9	Ash/Spent Sorbent Foundation		110	192			$303	30		67	$400	1
	SUBTOTAL 10.	**$3,651**	**$110**	**$6,869**			**$10,631**	**$1,063**		**$1,771**	**$13,465**	**22**

Client:	Nevada Power			**Report Date:**	03-May-2006
Project:	IGCC Plant Feasibility Study				10:17 AM

TOTAL PLANT COST SUMMARY

Case:	SuperCritical PC w/ Wet FGD & SCR, Valmy					
Plant Size:	600.4 MW,net	**Estimate Type:** Conceptual		**Cost Base (Jan.)**	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,435		322			$1,757	176		145	$2,077	3
11.2	Station Service Equipment	2,736		1,242			$3,978	398		328	$4,704	8
11.3	Switchgear & Motor Control	3,145		739			$3,884	388		427	$4,700	8
11.4	Conduit & Cable Tray		1,897	9,424			$11,320	1,132		1,557	$14,009	23
11.5	Wire & Cable		2,240	9,928			$12,167	1,217		1,673	$15,057	25
11.6	Protective Equipment	156		735			$892	89		98	$1,079	2
11.7	Standby Equipment	1,133		36			$1,168	117		129	$1,414	2
11.8	Main Power Transformers	3,296		216			$3,512	351		386	$4,249	7
11.9	Electrical Foundations		261	957			$1,218	122		268	$1,608	3
	SUBTOTAL 11.	**$11,901**	**$4,398**	**$23,598**			**$39,897**	**$3,990**		**$5,011**	**$48,898**	**81**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7		w/12.7								
12.2	Combustion Turbine Control	N/A		N/A								
12.3	Steam Turbine Control	w/8.1		w/8.1								
12.4	Other Major Component Control											
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	393		326			$719	72		99	$890	1
12.7	Distributed Control System Equipment	3,972		959			$4,931	493		407	$5,831	10
12.8	Instrument Wiring & Tubing	1,346		5,903			$7,249	725		997	$8,970	15
12.9	Other I & C Equipment	1,122		3,520			$4,642	464		383	$5,490	9
	SUBTOTAL 12.	**$6,833**		**$10,708**			**$17,541**	**$1,754**		**$1,885**	**$21,181**	**35**
13	Improvements to Site											
13.1	Site Preparation		87	2,282			$2,368	237		521	$3,126	5
13.2	Site Improvements		1,542	2,523			$4,065	406		894	$5,366	9
13.3	Site Facilities	2,763		3,590			$6,353	635		1,398	$8,386	14
	SUBTOTAL 13.	**$2,763**	**$1,628**	**$8,395**			**$12,786**	**$1,279**		**$2,813**	**$16,878**	**28**
14	Buildings & Structures											
14.1	Boiler Building		6,417	8,916			$15,333	1,533		2,530	$19,396	32
14.2	Turbine Building		6,468	9,524			$15,992	1,599		2,639	$20,230	34
14.3	Administration Building		449	749			$1,198	120		198	$1,515	3
14.4	Circulation Water Pumphouse		128	161			$290	29		48	$367	1
14.5	Water Treatment Buildings		352	459			$811	81		134	$1,026	2
14.6	Machine Shop		300	318			$618	62		102	$782	1
14.7	Warehouse		271	430			$701	70		116	$886	1
14.8	Other Buildings & Structures		166	223			$390	39		64	$493	1
14.9	Waste Treating Building & Str.											
	SUBTOTAL 14.		**$14,552**	**$20,781**			**$35,332**	**$3,533**		**$5,830**	**$44,695**	**74**
	TOTAL COST	**$349,069**	**$36,291**	**$337,449**			**$722,809**	**$72,281**		**$80,818**	**$875,908**	**1459**

INITIAL & ANNUAL O&M EXPENSES

SuperCritical PC w/ Wet FGD & SCR, Valmy

Cost Base (Jan.	2006
Heat Rate-net(Btu/kWh):	8749.7
MWe-net:	600.42
Capacity Factor: (%):	85

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	38.60	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	9.0	9.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	14.0	14.0

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost(calc'd)	$6,154,075	10.25
Maintenance Labor Cost(calc'd)	$9,537,119	15.88
Administrative & Support Labor(calc'd)	$3,922,799	6.53
TOTAL FIXED OPERATING COSTS	**$19,613,993**	**32.67**

VARIABLE OPERATING COSTS

Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost $	$/kWh-net
Maintenance Material Cost(calc'd)					$8,941,049	0.0020
Water(/1000 gallons)		1,233				
Chemicals						
MU & WT Chem.(lbs)	41,775	5,968	0.22	$9,238	$409,421	0.0001
Limestone (ton)	471	67	20.00	$9,421	$417,572	0.0001
Carbon (Mercury Removal) lb	1,177	168	9.84	$11,582	$513,347	0.0001
Ammonia (28% NH3) ton	232	33	200.00	$46,351	$2,054,351	0.0005
Subtotal Chemicals				$76,593	$3,394,691	0.0008
Other						
Gypsum Disposal (tons)	6,654	111	5.00		$172,040	0.0003
SCR Catalyst Replacement					$571,206	0.0001
Spent Mercury Catalyst (lb.)		168	0.38		$19,744	0.0000
Subtotal Other					$762,990	0.0002
Waste Disposal						
Fly Ash (ton)		379	5.00		$587,843	0.0001
Bottom Ash (ton)		95	5.00		$146,965	0.0000
Subtotal Solid Waste Disposal					$734,809	0.0002
By-products & Emissions						
Gypsum (tons)						
Subtotal By-Products						
TOTAL VARIABLE OPERATING COSTS					**$13,833,539**	**0.0031**

Appendix D Design Basis Document

This page is intentionally left blank

Design Criteria

WorleyParsons Report No. EJ-2006-01
Purchase Order 0001012232
WorleyParsons Job No. 53774010

Design Basis
Revision D

Nevada Power/Sierra Pacific

IGCC Market Status
and Feasibility Report:

DESIGN BASIS DOCUMENT

March 2006

Prepared for:

Sierra Pacific RESOURCES

Nevada Power.

Prepared by:
WorleyParsons Group, Inc.
2675 Morgantown Road
Reading, Pennsylvania 19607-9676 USA

WorleyParsons

TABLE OF CONTENTS

P:\Contracts_NevadaPower\Design Basis\2006-03-06_Nevada Power Design Basis Draft_RevC.DOC

LIST OF EXHIBITS

Revision Record

Revision	Date	Content
A	2/16/2006	Draft - Initial Issue to client for review
B	03/03/06	Revised to include coal analysis and other data from teleconference on 02/21/06. Added the E-Gas technology for gasifier.
C	03/08/06	Minor editorial corrections in Section 4
D	04/28/06	Changes to the Section 7 Cost Analysis and added Ely site parameters.

1 Site Description

1.1 Climate

Ambient conditions are required to be specified for the purpose of estimating performance of the power plant configurations and to size the equipment so that an accurate cost estimate can be made.

Ambient conditions and site characteristics are presented below:

Site Characteristic	Reid Gardner	Valmy	Ely	Units
Site Elevation above Mean Sea Level	1,700	4,500	6,100	ft
Average Atmospheric Pressure	13.82	12.46	11.73	psia
Topography	Flat	Flat	Flat	describe
Clearing and Grubbing	Minimal	Minimal	Minimal	describe
Wetlands Mitigation Required?	No	No	No	yes/no
Subsurface – Piles Required?	No	No	No	yes/no
Size Available				acres
Transportation				.
Coal Unloading Transportation	Rail	Rail	Rail	Rail, road, barge, etc
Coal Unloading on-Site Facilities	New	New	New	
Site Access Road				
Ash Disposal	On-site	On-site	On-site	
Design Point (Annual Average) Temperature – dry bulb	68	50	45	°F
Design Point (Annual Average) Coincident Relative Humidity	50	50	50	%
Rainfall – Maximum 24 hour				Inches
Rainfall – Maximum 1 hour				inches
Snow Loading	0			inches
Frost Depth				feet

1.2 Other Site Information

The following site-specific design parameters are considered, but not quantified for this study. Allowances for normal conditions and construction will be included in the concept level cost estimates except as noted.

- Flood plain considerations.
- Existing soil/site conditions.
- Water discharges and reuse: Zero discharge with evaporation pond.
- Solid Discharge: Onsite Landfill
- Seismic design: No specific requirements
- Buildings/enclosures: No generation building is required.
- Fire protection.
- Local code height requirements: No specific restrictions.

- Noise regulations – Impact on site and surrounding area.

1.3 Site Air Composition

While the basic composition of air is similar everywhere, concentrations of certain trace airborne components are important to the design of the air separation unit (ASU), and these can vary from site to site. For this concept evaluation, the compositions listed below are used. Before ASU manufacturers are contacted for quotes, this information must be replaced with actual site values.

Gas	Chemical Symbol	Molecular Weight	Parts per Million (by Volume)	% by Volume	% by Weight
Nitrogen	N_2	28.01	780,840	78.08	75.47
Oxygen	O_2	32.00	209,460	20.95	23.20
Argon	Ar	39.95	9,340	0.93	1.28
Carbon Dioxide	CO_2	44.01	350- 400		
Neon	Ne	20.18	18.21	0.0018	0.0012
Helium	He	4.00	5.24	0.0005	0.00007
Krypton	Kr	83.80	1.14	0.0001	0.0003
Xenon	Xe	131.30	0.087	0.0000087	0.00004
Carbon Monoxide	CO	28.01	20		
Hydrogen	H_2	2.02	10		
Methane	CH_4	16.04	10		
Ammonia	NH_3	17.03	1.0		
Acetylene	HC:HC	26.04	1.0		
Butane and Heavier Hydrocarbons			1.0		
Nitrous Oxide	N_2O	44.02	0.5		
Ethlylene	$H_2C:CH_2$	28.05	0.3		
Propylene	$CH_3CH:CH_2$	42.08	0.2		
Sulfur Dioxide	SO_2	64.06	0.1		
Ethane	CH_3CH_3	30.07	0.1		
Mercaptans			0.1		
Oxides of Nitrogen ($NO+NO_2$)			0.05		
Chlorides, chlorine, chlorine oxides			0.05		
Propane	$CH_3CH_2CH_3$	44.09	0.05		
Hydrogen Sulfide	H_2S	34.08	0.05		
All other Gaseous Impurities (other than Kr, Xe, Ne, and He)			nil		
Particulate Matter					c.

Notes:
a. Moist air can contain up to 6% moisture by volume, depending on temperature and relative humidity
b. Table modified from information taken from a Universal Industrial Gases Inc. article [1]
c. Less than 2.5 milligrams/cubic meter, with not more than 3 weight % of all particles larger than 2 microns. Particles to be non-corrosive and chemically inert

1.4 Water Sources and Re-Use

1.4.1 Water Permit Limitations

The water permit levels are shown below.

Water Permit Limits	Reid Gardner	Valmy
Raw Water		
Raw Water Source	wells	wells
Maximum Annual Rate, acre-ft/yr		
Maximum Instantaneous Rate, gpm		
Distance to Raw Water Source Tie-in Point	On-Site	On-Site
Water Quality	Per Paragraph 1.4.2	Per Paragraph 1.4.2
Raw Water Quantity		
Intake Structure Required	No	No
Potable Water		
Potable Water Source	Tie into plant system	Tie into plant system
Distance to Potable Water Source Tie-in Point, ft	1000	1000
Potable Water Quantity	Adequate	Adequate
Name of Operator	Nevada Power	Sierra Pacific
Grey Water		
Source of Water for Cooling Towers	Wells	Wells
Maximum Annual Consumption, acre-ft/yr	N.A.	N.A.
Maximum Instantaneous Rate, gpm	N.A.	N.A.
Distance to Grey Water Source Tie-in Point	N.A.	N.A.
Grey Water Quantity	N.A.	N.A.
Name of Operator	N.A.	N.A.
Wastewater		
Wastewater Discharge Allowed, Yes/No	No	No
Discharge Temperature Limits, °F		
Water Discharge Quality Limitations	None. Evaporation pond to be sized to suit needs	None. Evaporation pond to be sized to suit needs

1.4.2 Water Quality

At the concept level of this study, the water quality for both sites will be as shown in below. While this is adequate for the purpose of this evaluation, it is important to have a detailed water analysis to proceed beyond the concept level of evaluation.

Water Quality		**mg/l**	**mg/l as $CaCO_3$**
Silica	(SiO_2)	6.8	—
Calcium	(Ca)	76.0	189.0
Magnesium	(Mg)	16.0	66.0
Sodium	(Na)	20.0	44.0
Potassium	(K)	2.9	3.7
Bicarbonate	(HCO_3)	246.0	202.0
Sulfate	(SO_4)	56.0	58.0
Chloride	(Cl)	26.0	37.0
Nitrate	(NO_3)	6.9	5.6
Total dissolved solids (TDS)		457.0	—
Total hardness		—	255.0
pH		8.0	
Ionic strength (meq/l)		9.2×10^{-3}	
Temperature range, °F		40-80	
Biological considerations			

2 Design Fuels

2.1 Coal

The design coal basis for this study is a Power River Basin blend from the Black Butte Coal Company. The coal analysis will be based on a 40/60 blend from their coal pits 8 and 10, respectively. The coal analysis is presented as follows:

	Pit No. 8 Average	Pit No. 10 Average	Blend P8 (40%) & P10 (60%)
Proximate Analysis (AR)			
Moisture %	19.08	21.79	20.71
Ash %	7.38	6.79	7.03
Volatile %	29.95	29.44	29.64
Fixed Carbon %	43.97	42.06	42.82
BTU/lb	9,800	9,350	9,530
Sulfur %	0.57	0.39	0.46
Ultimate Analysis			
Carbon %	57.84	53.15	55.03
Hydrogen %	3.88	3.62	3.72
Nitrogen %	1.43	1.05	1.20
Oxygen %	10.78	12.85	12.02
Chlorine %	0.02	0.01	0.01
Mineral Analysis of Ash			
SiO_2	52.33	50.34	51.14
Al_2O_3	24.67	12.19	17.18
TiO_3	1.07	0.80	0.91
Fe_2O_3	4.67	6.12	5.54
CaO	6.50	10.94	9.16
MgO	2.42	2.91	2.71
K_2O	0.54	0.58	0.56
Na_2O	0.86	4.69	3.16
SO_3	3.13	-	1.25
P_2O_5	1.83	-	0.73
Reducing Ash Fusion Temp.			
Initial Deformation	2,397	1,995	2,156
Soft Temp. (H=W)	2,455	2,118	2,253
Hemis. Temp. ($H=\frac{1}{2}W$)	2,501	2,151	2,291
Fluid Temp.	2,569	2,247	2,376
Sulfur Forms			
Pyritic Sulfur %	0.11	0.19	0.16
Sulfate Sulfur %	0.01	0.01	0.01
Organic Sulfur %	0.39	0.25	0.31
Other Analysis			
T250 Temp. (Deg F)	2,750	2,350	2,510
EQ Moisture %	17.00	21.40	19.64

	Pit No. 8 Average	Pit No. 10 Average	Blend P8 (40%) & P10 (60%)
Hardgrove Grindability	47.14	48.74	48.10
Calculated Values			
Base to Acid Ratio	0.19	0.40	0.32
Silica Value	79.39	71.60	74.72
Dolomite %	59.45	54.87	56.70
Ash Precipitation Index	17.40	5.38	10.19
SiO_2 : Al_2O_3	2.12	4.13	3.33
lbs SO_2 / MBtu	1.15	0.83	0.96
SiO_2 : CaO	8.05	4.60	5.98

2.2 Secondary Fuel

Either natural gas or fuel oil can be utilized as a startup/backup fuel.

- **Reid Gardner**: Natural Gas available at a pressure of 1200 psig at the plant boundary
- **Valmy**: No 2 Oil

The composition of natural gas is as follows:

Natural Gas Component		Volume %
Methane	CH_4	80.67 %
Ethane	C_2H_6	8.75 %
Propane	C_3H_8	5.70 %
n-Butane	C_4H_{10}	1.16 %
Other combustible	Q	1.95 %
Carbon Dioxide	CO_2	0.34 %
Nitrogen	N_2	1.43 %
	Total	100.00 %

	HHV
Btu/scf	1,231 Btu/scf

The characteristics of the No. 2 fuel oil are as follows:

No 2 Fuel Oil Characteristic	
API Gravity, 60°F	32
Specific Gravity, 60/60°F	0.8654
Lb/US gallon, 60°F	7.2
Viscosity, centistokes 100°F	2.68
Viscosity, Saybolt Universal 100°F	35
Pour point, °F	Below zero
Temperature for pumping, °F	Atmospheric
Temperature for atomizing, °F	Atmospheric
Carbon residue, %	Trace
Sulfur, (Max.) %	0.7
Oxygen and Nitrogen, %	0.2
Hydrogen, %	12.7
Carbon, %	86.4
Sediment and water, %	Trace
Ash, %	Trace
Btu/gallon	141,000

3 Design Sorbent Composition

Limestone will be used as a design sorbent for this study. The limestone analysis is presented below:

		Reid Gardner	Valmy
Supplier/Mine			
Delivery Options		By Train	By Train
		Analysis, %	
Calcium Carbonate	$CaCO_3$	90%	90%
Magnesium Carbonate	$MgCO_3$	5%	5%
Silica	SiO_2	1%	1%
Aluminum Oxide	Al_2O_3	1%	1%
Iron Oxide	Fe_2O_3	1%	1%
Sodium Oxide	Na_2O	1%	1%
Potassium Oxide	K_2O	1%	1%
Balance		0%	0%
	Total	**100**	**100**

4 Environmental Requirements

The environmental approach is to evaluate each configuration on the same regulatory design basis, considering differences in site location, fuel and technology. It is expected and assumed in this study that the addition of a new unit at either Reid Gardner or Valmy site would result in a significant increase in net emissions (Exhibit 4-1), and the new units will be subjected to the New Source Review (NSR) as a Major Modification at an existing Major Stationary Source.

Exhibit 4-1
Significant Net Emissions Increase

POLLUTANT	NET EMISSION INCREASE
• Carbon monoxide	100 TPY
• Sulfur dioxide	40 TPY
• Nitrogen oxides	40 TPY
• Volatile organic compounds	40 TPY
• Particulate matter	25 TPY
• PM_{10}	15 TPY
• $PM_{2.5}$	10 TPY
• Lead	0.6 TPY
• Fluorides	3 TPY
• Sulfuric acid mist	7 TPY
• Mercury	0.1 TPY
• Beryllium	0.0004 TPY

TPY – tons per year

The NSR process requires installation of emission control technology meeting either Best Available Control Technology (BACT) determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county. Nevada counties currently designated by the U.S. EPA as non-attainment areas are presented in Exhibit 4-2. [2]

Exhibit 4-2
Non-attainment Areas in Nevada

County	Pollutant	Area Name	Classification
Clark	Carbon Monoxide	Las Vegas, NV	Serious
	8-Hr Ozone	Las Vegas, NV	Subpart 1
	PM-10	Clark Co, NV	Serious
Washoe	Carbon Monoxide	Reno, NV	Moderate, ≤12.7 ppm
	PM-10	Washoe Co, NV	Serious

The Reid Gardner site is located in Clark County and the Valmy site is located in Humboldt County. Thus, for this study, the new unit at the Reid Gardner site will be designed to meet LAER regulations (Exhibit 4-3), and the new unit at the Valmy site will be designed to meet BACT regulations (Exhibit 4-4)

Exhibit 4-3
Presumptive LAER Emission Values

Process	Pollutants	Emissions Limitation	Type of Technology
PC Boiler	PM/PM-10	0.012 lb/10^6 Btu	Fabric Filter or ESP
	Sulfur Dioxide	0.06 lb/10^6 Btu	Low-Sulfur Fuel, FGD
	Nitrogen Oxides	0.07 lb/10^6 Btu	SCR
	Carbon Monoxide	0.10 lb/10^6 Btu	Combustion Controls
IGCC	PM/PM-10	0.0145 lb/10^6 Btu	Syngas candle filter, water scrubber
	Sulfur Dioxide	0.0064 lb/10^6 Btu	AGR
	Nitrogen Oxides	3.5 ppmvd @15% O_2	Nitrogen or steam diluent injection, Combustion controls, SCR
	Carbon Monoxide	25 ppmvd @15% O_2	Combustion Controls

Exhibit 4-4
Presumptive BACT Emission Values

Process	Pollutants	Emissions Limitation	Type of Technology
PC Boiler	PM/PM-10	0.015 $lb/10^6$ Btu	Fabric Filter or ESP
	Sulfur Dioxide	0.2 $lb/10^6$ Btu	Low-Sulfur Fuel, FGD
	Nitrogen Oxides	0.15 $lb/10^6$ Btu	SCR
	Carbon Monoxide	0.15 $lb/10^6$ Btu	Combustion Controls
IGCC	PM/PM-10	0.0145 $lb/10^6$ Btu	Syngas candle filter, water scrubber
	Sulfur Dioxide	0.128 $lb/10^6$ Btu	AGR
	Nitrogen Oxides	15 ppmvd @15% O_2	Nitrogen or steam diluent injection, Combustion controls
	Carbon Monoxide	25 ppmvd @15% O_2	Combustion Controls

5 Air Separation Unit

The ASU design will be based on the ambient air quality as presented in Section 1.3 and cooling water quality as presented in Exhibit 5-1,

Exhibit 5-1
Required Cooling Water Quality

Quality or Impurity	Parameter	Value
pH value		7.6 to 7.8
Carbonate hardness		8 to 10° DH (German degrees)
Carbonic acid	Free Combined Corroding	8 to 15 mg/l 8 to 15 mg/l None
Rysnar index		6.5
Oxygen	At least	4 to 5 mg/l
Chloride ions	Maximum	10 mg/l
Sulphate ions	Maximum	50 mg/l
Nitrates and Nitrites	Maximum	10 mg/l
Ammonia	Maximum	10 mg/l
Phosphates and silicates		not significant
Iron and manganese		0.1 to 0.2 mg/l
Suspended solids	Maximum	10 mg/l

Note: The cooling water must be free of living organisms, biological growth, algae.

The quality of the low pressure steam used for regeneration of the front end separation of the ASU will be generally as specified in Exhibit 5-2. However, the specification will be modified to suit OEM requirements.

Exhibit 5-2
Low Pressure Steam Quality

Property	Chemical Formula	Value
Pressure/Temperature		10 bars sat
pH value		7.0 to 9.5
Conductivity		<0.2 µS/cm
Silicates	SiO_2	<0.02 mg/kg
Iron	Fe	<0.02 mg/kg
Copper	Cu	<0.003 mg/kg
Sodium	Na	<0.01 mg/kg
Organics		<0.2 mg/kg
Calcium + Magnesium	Ca + Mg	<0.05 mg/kg
Oxygen	O_2	<0.25 mg/kg
Chloride ions	Cl^-	<0.1 mg/kg
Bromide ions	Br^-	<0.1 mg/kg
Iodide ions	I^-	<0.1 mg/kg
Fluoride ions	F^-	<0.02 mg/kg
Sulphate ions	SO_4^{2-}	<0.1 mg/kg
Solids		<1.0 mg/kg

6 Balance of Plant

The balance of plant requirements are as follows:

	Reid Gardner	Valmy
Cooling System – PC Plants	Parallel Wet/Dry Condensing system (50/50)	Parallel Wet/Dry Condensing system (50/50)
Cooling System – IGCC Plants	Dry Condensing	Parallel Wet/Dry Condensing system (50/50)
Storage - Fuel and Other		
Coal	60 days - new	60 days - new
Slag	30 days - new	30 days - new
Sulfur	30 days - new	30 days - new
Sorbent	7 days - new	7 days - new
Plant Distribution Voltage		
Motors below 1 hp	110/220 volt	110/220 volt
Motors 250 hp and below	480 volt	480 volt
Motors above 250 hp	4,160 volt	4,160 volt
Motors above 5,000 hp	13,800 volt	13,800 volt
Steam and Gas Turbine generators	24,000 volt	24,000 volt
Water and Waste Water		
Makeup Water	Raw water supply is from wells.	Raw water supply is from wells.
Feed water	The quality of feedwater (i.e., water treatment systems) required is similar regardless of the technology, except for supercritical technologies that require higher quality feedwater	The quality of feedwater (i.e., water treatment systems) required is similar regardless of the technology, except for supercritical technologies that require higher quality feedwater
Process Wastewater	Water associated with gasification activity and storm water that contacts equipment surfaces will be collected and discharged to waste water evaporation ponds	Water associated with gasification activity and storm water that contacts equipment surfaces will be collected and discharged to waste water evaporation ponds

	Reid Gardner	Valmy
Sanitary Waste Disposal	Design will include a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge will be hauled to onsite landfill	Design will include a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge will be hauled to onsite landfill
Water Discharge	Most of the wastewater is to be recycled for plant needs. Blowdown will be treated and discharged to existing evaporation pond.	Most of the wastewater is to be recycled for plant needs. Blowdown will be treated and discharged to existing evaporation pond.
Solids	Fly ash, bottom ash, scrubber sludge, and gasifier slag are solid wastes that are classified as non-hazardous wastes. Onsite waste disposal is assumed to have the capacity to accept waste generated throughout the life of the facility Solid wastes sent to onsite disposal. Solid waste generated that can be recycled or reused will have a zero cost to the technology	Fly ash, bottom ash, scrubber sludge, and gasifier slag are solid wastes that are classified as non-hazardous wastes. Onsite waste disposal is assumed to have the capacity to accept waste generated throughout the life of the facility Solid wastes sent to onsite disposal. Solid waste generated that can be recycled or reused will have a zero cost to the technology

6.1 Plant Configurations

A summary of the plant configurations considered in this study is presented below. Components for each plant configuration are described in the following subsections.

	Reid Gardner		Valmy	
Case	**RG1**	**RG2**	**V3**	**V4**
Unit Cycle	IGCC	Rankine, PC	IGCC	Rankine, PC
Steam Cycle, psig/°F/°F	1800/1050/1050	3700/1100/1100	1800/1050/1050	3700/1100/1100
Cooling System	Hybrid system with 50% load to dry and 50% load to wet cooling	Hybrid system with 50% load to dry and 50% load to wet cooling	Hybrid system with 50% load to dry and 50% load to wet cooling	Hybrid system with 50% load to dry and 50% load to wet cooling
Combustion Turbine	2 x GE 7FB		2 x GE 7FB	
Gasifier/Boiler Technology	E-Gas	Supercritical PC	E-Gas	Supercritical PC
Oxidant	TBD mol% O_2	Air	TBD mol% O_2	Air

	Reid Gardner		Valmy	
Case	**RG1**	**RG2**	**V3**	**V4**
Availability Target	85% with natural gas back up (No spare gasifier)	90%	85% with spare gasifier	90%
Nominal Output, MW	500	600	500	600
Transmission Interconnect	345 kV on site	345 kV on site	345 kV on site	345 kV on site
Acid Gas Removal	TBD		TBD	
Sulfur Removal/Recovery	90%	Wet FGD/ Gypsum	90%	Wet FGD/ Gypsum
Mercury Removal	TBD	TBD	TBD	TBD
NOx Control	Nitrogen Dilution/SCR	LNB/OFA/SCR	Nitrogen Dilution/	LNB/OFA/SCR
CO_2 Capture	No provision	No provision	No provision	No provision
CO_2 Sequestration	none	none	none	none
Byproducts	No Resale Value	No Resale Value	No Resale Value	No Resale Value

7 Cost Analysis

Capital and production cost estimates will be developed for each plant based on the plant equipment requirements factored from WorleyParsons cost database.

7.1 Capital Costs

The capital costs at the Total Plant Cost level include equipment, materials, labor, indirect construction costs, engineering, and contingencies.

Each major component will be based on WorleyParsons' database reference, establishing a basis for subsequent comparisons and easy modification as the technology is further developed.

- Total Plant Cost, or "Overnight Construction Costs" values will be expressed in January 2006 year dollars.
- The estimates represent commercial technology plants or n^{th} plants for the PC configuration and initial commercial offerings for the IGCC.
- The estimates represent a complete power plant facility, standalone with no interconnection with any existing facility.
- The estimate boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system but terminating at the high voltage side of the main power transformers.
- Costs are grouped according to a process/system oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.
- Exclusions include:
  - Switchyard costs.
  - Infrastructure to plant boundary (e.g. natural gas pipeline)
  - EPC Contractor risk
  - Escalation during construction.
  - Project financing costs.
  - Land and right of way
  - Preproduction costs
  - Inventory, capital and spare parts
  - Owners costs

The capital cost, specifically referred to as Total Plant Cost (TPC) for each power plant, will be estimated for the categories consisting of bare erected cost, engineering and home office overheads, and fee plus contingencies. The TPC level of capital cost is the "overnight construction" estimate.

For the Valmy site, a breakout pricing for the back-up oil system will be provided.

7.2 Operation and Maintenance Costs

The operating costs and related maintenance expenses (O&M) described in this section pertain to those charges associated with operating and maintaining the power plants over their expected life.

Operation and maintenance cost values will be determined on a first-year basis.. Quantities for major consumables such as fuel and sorbent will be taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables will be evaluated on the basis of the quantity required using reference data. Operation cost will be determined on the basis of the number of operators. Maintenance costs will be evaluated on the basis of requirements for each major plant section. The operating and maintenance costs will be then converted to unit values of \$/kW-year or ¢/kWh.

The O&M cost estimates will be based on the following:

- The operating and maintenance expenses and consumable costs will be developed on a quantitative basis.
- Operating labor cost will be determined on the basis of the number of operators required.
- Maintenance cost will be evaluated on the basis of relationships of maintenance cost to initial capital cost.
- Cost of consumables, will be determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.
- Byproduct credits for commodities such as gypsum and emissions are not considered due to the variable marketability.
- Each of these expenses and costs will be determined on a reference year basis and escalated to a first-year basis, and subsequently levelized over the life of the plant and reported on the 10th year basis through application of a levelizing factor to determine the value that forms a part of the economic evaluation. This amount, when combined with fuel cost and capital charges, results in the figure-of-merit, COE.

These O&M costs will be estimated on a reference year (January 2006) basis and then escalated to a first-year basis, in January 2010 dollars. The first-year costs assume normal operation and do not include the initial startup costs. The operating labor, maintenance material and labor, and other labor-related costs will be combined and then divided into two components: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. The first-year O&M cost estimate allocation will be based on the plant capacity factor.

The other operating costs, consumables and fuel, will be determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis. The inputs for each category of operating costs and expenses will be identified in the succeeding subsections, along with more specific discussion of the evaluation processes.

7.3 Cost of Electricity (COE)

The economic performance will be evaluated by Nevada Power and Sierra Pacific, using their own financial models.

8 References

1 Universal Industrial Gases, Inc. "Air: Composition and Properties." http://www.uigi.com/air.html#Composition%20of%20Air

2 U.S. Environmental Protection Agency, Green Book, Currently designated non-attainment areas for all criteria pollutants, September 29, 2005, http://www.epa.gov/oar/oaqps/greenbk/ancl.html#NEVADA

Appendix E Comparison of Various IGCC Technologies

WorleyParsons

resources & energy

WorleyParsons Report No. EJ-2006-01
Nevada Power Purchase Order 0001012232
WorleyParsons Job No. 53774010

20-Jun-06 11:29 Revision C

Nevada Power IGCC Market Status and Feasibility Study
Comparison of Various IGCC Technologies
Appendix E

June 2006

Prepared for:

Nevada Power

Sierra Pacific RESOURCES

Prepared by:
WorleyParsons Group, Inc.
2675 Morgantown Road
Reading, Pennsylvania 19607-9676 USA

when experience counts

TABLE OF CONTENTS

P:\Contracts_NevadaPower\Report\20 June NEVADA POWER - Rev C Comparison Write- Up PEM untrkA.doc

LIST OF EXHIBITS

Revision Record

Revision	Date	Content
A	8 May 2006	Draft - Initial Issue to client for review
B	8 June 2006	Incorporate Client Comments
C	20 June 2006	Incorporate Client Comments

Notice

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by WorleyParsons.

Due to the limited timeframe available, it was not possible to obtain project-specific information from the gasifier licensors. Therefore, WorleyParsons in-house models and data, where applicable, were utilized to predict the gasifier syngas yields and technical limitations. This in-house modeling, although we believe to be representative of the selected configurations, will likely vary from the official vendor information, design standards and conservatisms (margins).

Although, the basis of this work reflects the best technical and cost inputs that where available at the time the work was performed, WorleyParsons does not take direct responsibility for decisions which are based on the conceptual results presented in this study.

TERMINOLOGY

ABS	Ammonium Bisulfate
AGR	acid gas removal
ASU	air separation unit
BEC	Bare erected cost
Btu	British thermal unit
ºC	degrees Celsius
CC	combined cycle
CO	carbon monoxide
CO_2	carbon dioxide
COE	cost of electricity
COS	Carbonyl sulfide
CT	combustion turbine
DOE	Department of Energy (United States)
EAF	equivalent availability factor
ºF	degrees Fahrenheit
fps	feet per second
GADS	Generating Availability Data System
GE	General Electric
GT	gas turbine
Hg	mercury
HHV	Higher Heating Value
HRSG	heat recovery steam generator
IDC	Interest during construction
IGCC	Integrated Gasification Combined Cycle
kW, kWe	kilowatt electric
kWt	kilowatt thermal
MDEA	methyl diethanolamine
MMBtu	million Btu
MSL	mean sea level
MW, MWe	megawatt electrical
MW_t	megawatt thermal
NERC	North American Electric Reliability Council
NG	natural gas
NOx	nitrous oxides
O_2	oxygen
OEM	original equipment manufacturer
O&M	Operation and Maintenance
Part.	Particulate emissions
PC, pc	pulverized coal
PM	particulate material
ppb	parts per billion
ppm	parts per million
PRB	Power River Basin (coal)
psia	lb/square inch (14.696 psi = 1 atm)
S	sulfur content of fuel
scf	standard cubic feet
scfd	standard cubic feet per day
SCR	selective catalytic reduction
SO_2	sulfur dioxide
SRU	sulfur recovery unit
STG	steam turbine generator
SNG	Synthetic Natural Gas
Syngas	Synthesis gas
t	short ton (2,000 lbs)
TBtu	tera Btu, or 10^{12} Btu
TG	turbo-generator, (turbine-generator)
TGTU	tail gas treatment unit
ton	short ton, (2000 lbs)
t/h, tph	ton per hour
t/y, tpy	ton per year
TPC	Total plant cost
US, U.S.	United States
USD, US$	the United States Dollar
USDOE	United States Department of Energy
VOC	volatile organic compound
y, yr	year

1 Introduction / Summary

1.1 Scope

Nevada Power/Sierra Pacific instructed WorleyParsons to perform an IGCC market status analysis and feasibility study. The results of the study are contained in three Documents.

a) The Design Basis Document

b) The Performance and Estimate Report

c) The Comparison of Various IGCC Technologies Report.

The following topics have been addressed in this IGCC Technologies Report:

a) A brief overview of the history of solid fuel gasification and IGCC, the relatively recent developments in the technology, and future development plans and programs, including a discussion on current government funded programs in clean coal technology.

b) A description and review of each of the commercial gasification technologies, including a status of each technology with regards to current commercial operation, the applicability of each technology for the fuels available, and the typical performance of each technology for syngas production.

c) Power plant design issues to include gas turbine operation and performance with regard to the use of syngas; HRSG issues especially with regard to potential impacts due to supplemental firing and gas turbine operation on back up fuel; and STG issues.

d) An analysis of the key issues with regard to the use of IGCC as a technology. This will include the pros and cons of such issues as emissions, sulfur removal, mercury removal, and CO_2 sequestration. The analysis will also address economic issues, maintenance issues, the production and handling of by-products. It is understood that Sierra Pacific is an electric generating company; however, the by-products produced by gasification are significant, and should be addressed commercially as something that could defray some O&M costs.

1.2 Summary / Conclusions

The history of operation of gasifiers and IGCC systems, irrespective of the design and licensor, has shown that each unit had some problems, and generally the projects were not initially successful. However, it is noted that over the years, the sources of the major problems were identified, and engineering solutions found. Therefore, it can be logically expected that future units will likely experience fewer overall problems, especially where experience exists for similar fuels. Although the reliability has improved, long term operation of existing IGCC facilities will be required to demonstrate performance, availability and reliability levels that are expected of a mature PC unit.

For the next generation of IGCC plants, the cost, performance, availability and reliability of the units with the improvements planned by the IGCC licensors remains yet to be demonstrated. As more IGCC plants come on line, all these data will become publicly available to determine long-term values for comparison to that of a PC unit.

Due to the complexity of coal gasification process by itself and due to the integration requirements with the power block in IGCC configuration, it is expected that some problems will still exist for the future plants that need to be resolved. This is not uncommon in the industry as the experience shows that even the coal-fired boilers experience problems that are unique to a design and coal combination, but problems are generally solvable. IGCC's gasification/AGR/power block integration complexity results in more opportunity for start-up problems and unplanned outages. It is expected that initial operating periods for an IGCC will incur lower availability than conventional PC.

IGCC Licensors have stated that they expect IGCC power plants to be 20 - 25 % more expensive than an equivalent PC plant. In addition, an IGCC plant will have more cost uncertainty than a Pulverized Coal plant due to the limited actual cost data in the industry.

Also, because of the effects of elevation on Gas Turbine output, the cost per kW of an IGCC plant will be higher at a higher elevation. (See Section 4.1 for details)

Advances in syngas cleanup systems, including experience with mercury removal suggests a promising future for the IGCC technology, as environmental restrictions become tighter. Also, developments in the gas turbine technology, including improved performance and emissions reduction techniques, better integration with ASUs, and other advancements, are projected to lower the overall IGCC plant heat rate, and unit costs. However, these projections along with the success of the new gas turbine and ASU integration concepts are yet to be proven in actual installation.

In summary, IGCC is an emerging technology which has some potential advantages with respect to Pulverized Coal, especially in emissions and efficiency. However, the costs, performance, availability, reliability and maintainability of the new generation of IGCC systems are yet to be demonstrated.

2 Gasification History and Developments

2.1 History

Gasification in the broadest sense is the production of gaseous fuel from liquid and solid fossil fuels. It was first practiced commercially in the early 19th century in England, and then in North America through the pyrolysis (heating in the absence of air) of coal in retorts to produce Town Gas for distribution to domestic and industrial consumers.

The coke remaining from the pyrolysis of coal was then used to make Producer Gas by blowing air through a red-hot bed of coke. This produces a low quality fuel gas containing mainly carbon monoxide as a combustible, but is a cheap and easy process. At the end of the 19th century, the technique of steam blowing alternating with air blowing was introduced. This produced a Water Gas containing equal proportions of carbon monoxide and hydrogen. Water Gas plants were very flexible, supplying a controlled output to balance the manufacture of fuel gas. This gas called the synthesis gas or 'syngas' has been the basic product of gasification ever since.

Throughout the first half of the 20th century, reticulated Town Gas systems grew and Water Gas became the major source of hydrogen for the manufacture of ammonia, the basic ingredient of the new synthetic fertilizer industry. The drawback of Water Gas plants is that they operate only a little over atmospheric pressure, whereas ammonia has to be synthesized at high pressure. Water Gas plants for ammonia manufacture were big and cumbersome, and showed no benefit in large scale.

In the middle of the century, two major developments occurred. The first was the development of bulk oxygen Air Separation Units (ASUs), using the cryogenic separation of air. These enabled cyclic gasification processes to become continuous operation plants and at an elevated pressure.

Pressurized gasification was further developed in South Africa in the 1950s for the production of transportation liquids, due to the political situation. The commercial development of coal gasification in the US began in the 1950s with several atmospheric gasification pilot units funded by the predecessors of DOE. However, the abundance of domestic natural gas and oil in the Middle East resulted in little interest in coal gasification. With the oil embargo and increased oil prices, the renewed development of pressurized coal gasification in the 1970s resulted in the IGCC concept. The use of pressurized coal gasification in the US was first demonstrated by TVA at the Ammonia from Coal Project at Muscle shoals, Alabama in the late 1970s – in a Texaco 200 tpd coal gasifier. The subsequent EPRI Cool Water and Tennessee Eastman gasification projects directly benefited from this TVA project.

Due to the historically low price for oil and natural gas, coal gasification's high capital cost resulted in minimal development of coal gasification for power production from the synthesis gas (syngas) – Integrated Gasification/Combined Cycle (IGCC). Government subsidies have been the primary driver in the continued development of IGCC.

2.2 Current Developments

According to the DOE Worldwide Gasification Database, there are 130 total "active-ready" operating gasifiers worldwide. Twenty eight of these are fueled with coal or Petroleum-coke. In the U.S., while there are a number of gasification facilities operating on coke or residuals, the list of operating coal gasifiers is brief, as shown below. [1]

- Tampa Electric IGCC– Texaco
- Wabash River IGCC – E-Gas
- Eastman Chemical – Texaco
- Dakota Gasification Company – Lurgi dry-ash

While there are a number of Gasification facilities producing chemicals, Hydrogen and / or steam, there are only two large “F” Class (GE 7FA) IGCC plants in the US (Tampa Polk Station and Wabash River) where the gasifier steam is superheated in the HRSG and integrated with the STG operation.

2.3 Future Developments

FutureGen

A DOE initiative funded to build the first coal-based integrated sequestration and hydrogen production research power plant with near-zero emissions. Several major utilities have announced plans to build IGCC plants, in anticipation of being selected to host the FutureGen plant. FutureGen started as Vision 21, a DOE project consisting of a series of interconnected modules for “sequestration” ready power plant.

The developments listed below are the key to long-term commercialization of gasification technology with superior environmental benefits into the mix for existing and new power plants:

- Advanced gasification
- Gas cleaning and conditioning – removal of H_2S, HCl, particulates and trace metals
- Advanced gas separation (membranes) – recovery of O_2, H_2 and O_2
- Product and byproduct utilization
- CO_2 Capture and Sequestration

Coproduction – Electricity and Oil/Chemicals/H_2

The coporduction of electricity and chemicals/hydrocarbons can be accomplished:

- Hydrogen Production
- Synthetic Natural Gas (SNG)

- Fischer-Trospch (FT) Liquids –
- Mixed Alcohols – commercialization of mixed-alcohol catalyst for production of methanol, ethanol and higher alcohols.
- Chemicals – methanol, ammonia

Other Future Developments

There are other projected improvements in IGCC technology, including:

- Improved gas and air separation using membranes, Improved Combustion Turbines.
- Combustion Turbines, Including improved F series Gas Turbines, with an aim to lower NOx below 10 ppm and improve efficiency. Other developments could include Hydrogen Turbines and fuel cell technologies.

2.4 Government Funded Clean Coal Technology Programs

Clean Coal Technology Program (CCT)

The CCT program was established in 1985 to demonstrate the commercial feasibility of CCTs to respond to a growing demand for a new generation of advanced coal-based technologies characterized by enhanced operational, economic and environmental performance. There were 5 solicitations during the CCT program from 1986 to 1992. Three IGCC commercial-scale demonstration units were funded by the CCT program.

- Pinon Pine - A 99 MW (net), air-blown, pressurized, fluid-bed gasification IGCC project using the KRW technology with 2-stage hot gas desulphurization (in-bed and external). Operation on coal was from 1998 thru 2000.
- Wabash River - A 262 MW O_2-blown, pressurized, entrained-bed gasification IGCC project using the ConocoPhillips E-Gas (formerly Destec) technology.
- Tampa Electric (Polk) - A 250 MW O_2-blown, pressurized, entrained-bed gasification IGCC project using the GE Energy (Formerly Texaco) technology.

Clean Coal Power Initiative (CCPI)

The CCPI is an industry/government cost share partnership to demonstrate clean coal technologies at sufficient scale to ensure proof-of-operation prior to commercialization. CCPI projects will support the objectives for the several federal government programs – Clear Skies Initiative, Global Climate Change Initiative, Clean Coal Initiative (Vision 21 and FutureGen) and the Hydrogen Initiative. Three pending IGCC-related projects are:

- Gilberton Coal-to-Clean Fuels and Power Project

- Mesaba Energy Project –600 MW IGCC.
- Demonstration of a 285 MW Coal-based KBR Transport Gasifier –285 MW IGCC.

Energy Policy Act of 2005 (EPACT 2005)

The EPACT2005 provides for financial incentives for coal, biomass and petcoke projects for IGCC and as a substitute for natural gas (chemicals, steel, and fertilizer):

- Investment tax credits – 20% (on the gasification-related units, not the power unit)
- Loan guarantees – 80%
- Direct grants – up to 50%

These incentives can reduce the COE differential between PC and IGCC. Papers from the 2005 GTC showed that these incentives are worth $2 to $4 per MWH. However, the timing for the incentives is uncertain and specific appropriations have not been legislated. [2]

The next round of IGCC plants supported by these government incentives will be considered “3rd-of-a-kind” in the development of IGCC technology.

3 Commercial Gasification Technologies

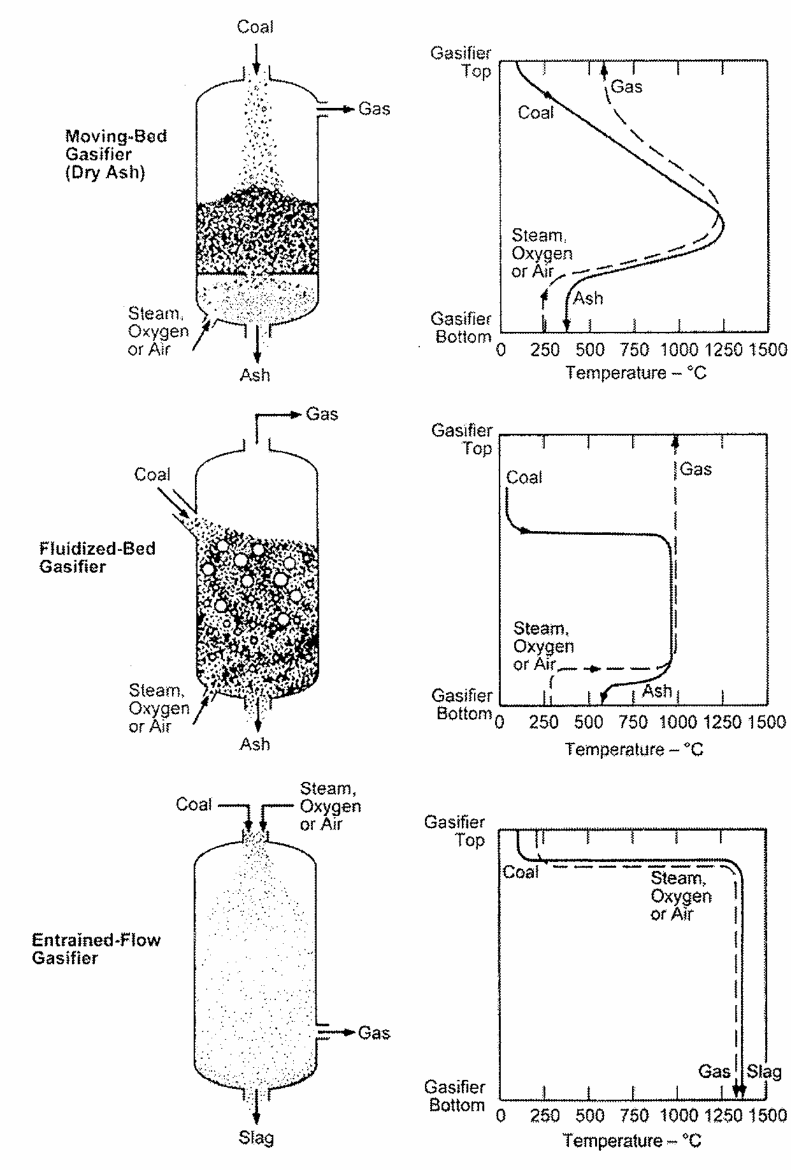
3.1 Gasifier Types

There are three major categories of gasification technology:

- Moving Bed, (e.g., Lurgi, BGL)
- Fluidized Bed (e.g., HT Winkler, KBR Transport, GTI U Gas), and
- Entrained-Flow (e.g., GE, E-Gas, Shell)

The schematic diagrams showing the fundamental gasification design principles of these technologies and the temperature profiles is shown below in Exhibit 3-1. The salient features of these technologies are presented in Exhibit 3-2.

Exhibit 3-1
Schematic of Gasification Technologies



Reference Source: [3]

Exhibit 3-2
Features of Various Gasification Technologies

Gasifier Type	Entrained-Flow	Moving Bed		Fluidized Bed	
Ash State	Slagging	Dry Ash	Slagging	Dry Ash	Agglomerating.
Feed Size	<100 µm	6 - 50 mm		6 -10 mm	
Fines Handling	Unlimited	Limited	Better than dry ash	Good	Better than dry ash
Outlet Gas Temp, °F.	2,300-2,900	800-1200		1650 -1,950	
Operating Pressure, psig	500 - 1000	~450		~400	
Oxygen Demand	High	Low		Moderate	
Steam Demand	Low	High		Moderate	
Comments	High Carbon Conversion	Hydrocarbons in gas		Lower Carbon Conversion	

A major distinguishing feature of the gasification types is the temperature profile which greatly influences the syngas composition, including the presence of methane, tars and oils. The higher temperatures of the entrained gasifiers tend to eliminate the tars and oils and reduce the methane levels. Tars and oils add unique requirements to the overall IGCC process, and increase the risk of fouling and contamination to downstream components. The only solid waste stream for the entrained-flow gasifiers is inert slag which may be saleable. The high reaction rate of the entrained-flow gasifiers also allows the greater syngas output per unit volume of gasifier, an important consideration when fuelling large combustion turbines. Further more, the relatively high H_2/CO ratio in the syngas coming out of the entrained-flow gasifier helps reduce the NOx and CO emissions from the combustion turbines.

For IGCC, pressurized gasification processes are preferred as the combustion turbine requires the syngas at pressure. Having all processes at pressure helps the overall economics with reduced vessel sizes and will generally improve the synthesis reactions and overall plant performance. Historically, most entrained-bed gasification processes for IGCC are also oxygen blown, as the reduced syngas volume is easier to cool, clean up and introduce into the combustion turbine, and also the heating value is more compatible with existing gas turbine designs of major OEMs. Fluidized beds are typically air blown.

3.2 Entrained Flow Gasifiers

Entrained-flow gasifiers have been utilized in the majority of commercially sized IGCC projects and represent the most widely demonstrated technology for coal based IGCC.

There are three main competitors providing entrained flow gasifiers. GE Energy recently purchased and is marketing the Texaco technology. ConocoPhillips purchased and is commercializing the E-Gas technology. Shell is marketing their own developed technology. The following table presents the pertinent characteristics of the GE, ConocoPhillips and Shell gasifiers.

Exhibit 3-3
Entrained Flow Gasification Technologies

Technology	GE Energy (formerly Texaco)	E-Gas ConocoPhillips	Shell
Feed System	Coal in Water Slurry	Coal in Water Slurry	Dry Coal. Lock Hopper and Pneumatic Conveying
Gasifier Configuration	Single Stage Downflow	Two Stage Upflow	Single Stage Upflow
Gasifier Wall	Refractory	Refractory	Membrane Wall
Pressure (psig)	500-1000	Up to 600	Up to 600
Syngas Cooling	Quench and/or Radiant Heat Recovery	Convective Heat Recovery (Fire Tube)	Convective Heat Recovery (Water Tube)

Commercial positioning and alliances help to promote the entrained bed gasification technologies to the forefront with the following Alliances:

- Conoco-Phillips (E-Gas) and Fluor
- Shell and Uhde
- GE Gasification and Bechtel
  (GE's commercial attractiveness is also enhanced with their "Product-Line" commercial offering approach to gasification for IGCC applications.)

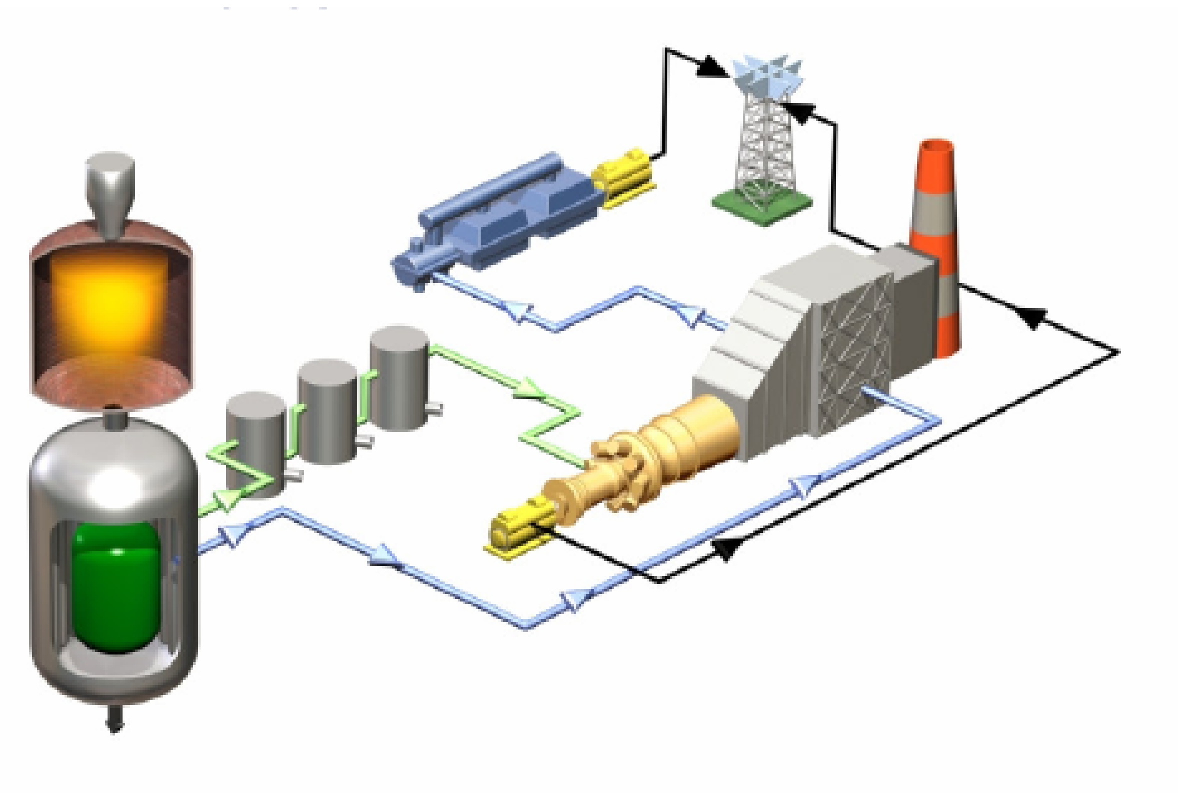
Typical entrained flow gasifier systems are shown below:

GE Energy Gasifier

A coal/ water slurry and an oxygen rich stream are fed into the GE gasifier and reacted at high temperature and pressure to produce a medium-Btu syngas. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it forms a solid slag. Feedwater flows into the high temperature radiant syngas cooler which cools the syngas and produces high pressure steam for use in the steam bottoming cycle.

The cooled syngas enters a syngas scrubber and hydrolysis reactor to remove the chlorides and to convert the COS to H_2S. The scrubbed gas is further cooled in low temperature heat recovery exchangers prior to entering an Acid Gas Removal system. The low sulfur gas leaving the AGR is re-heated against the raw gas going to the AGR process, sent to a power recovery turbine and then proceeds to the combustion turbine. A Claus unit is utilized to generate an elemental sulfur byproduct from the acid gas stream. The oxygen enriched Claus plant is designed with both air and oxygen feeds.

Exhibit 3-4
GE / Texaco Gasifier System



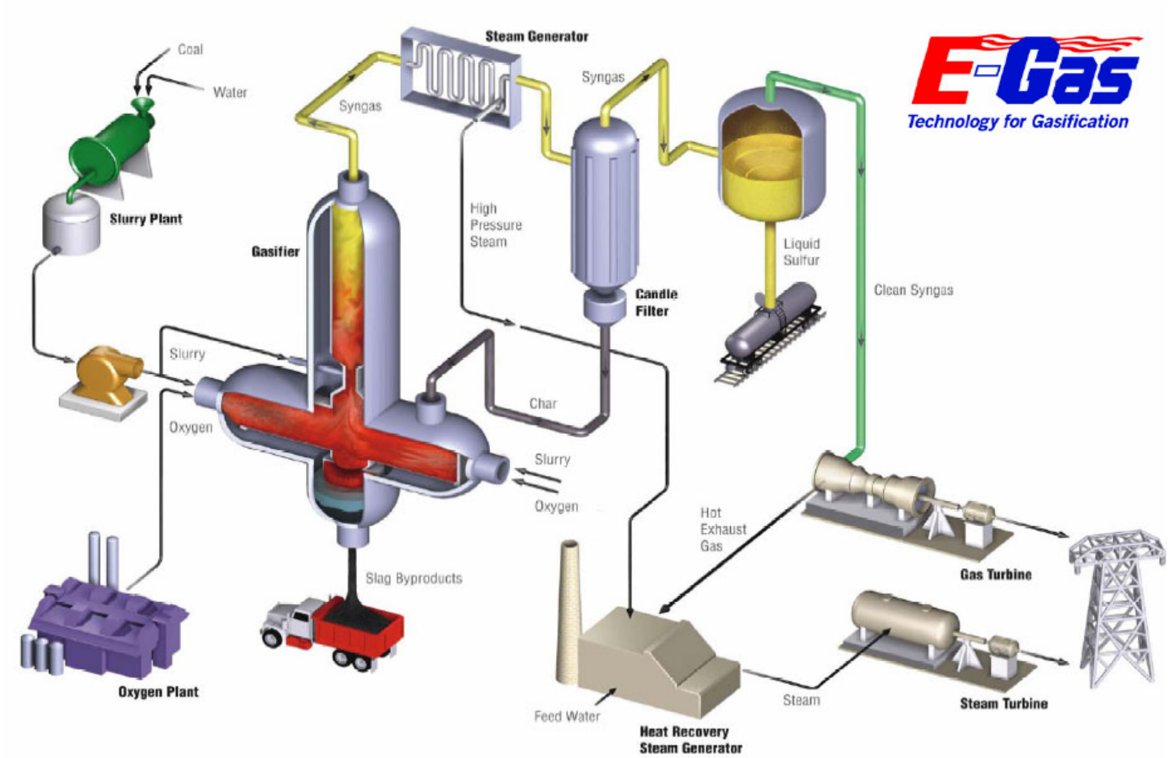
Source: GE [4]

ConocoPhillips (CoP) E-Gas Gasifier

The ConocoPhillips (CoP) E-Gas gasifier is a 2-stage, entrained-flow, oxygen-blown, continuous slagging gasifier. A coal/ water slurry and a 95% oxygen rich stream are fed into the first stage of the E-Gas gasifier. In this first stage, the coal slurry goes through an exothermic partial oxidation reaction to generate syngas and to provide heat to melt the coal ash and for the second stage gasification reactions. The molten ash falls through a tap at the bottom of the first stage gasification chamber into a water quench to form an inert slag. The syngas flows into the gasifier's second stage where additional coal slurry is injected. The coal is pyrolyzed in an endothermic reaction with the hot first stage syngas at a reduced temperature, to yield a syngas of enhanced heating value and composition.

The syngas enters the syngas cooler to produce high pressure steam. This high pressure steam is utilized in both the gasification process as well as the steam bottoming cycle. Subsequently, particulates are removed by the hot/dry candle filters and are recycled to the gasifier. After additional cooling, the syngas is water scrubbed to remove chlorides, and passed through a catalyst to hydrolyze the COS so it can be removed in the Acid Gas Removal (AGR) train as H_2S.

Exhibit 3-5
Conoco Phillips Gasifier System



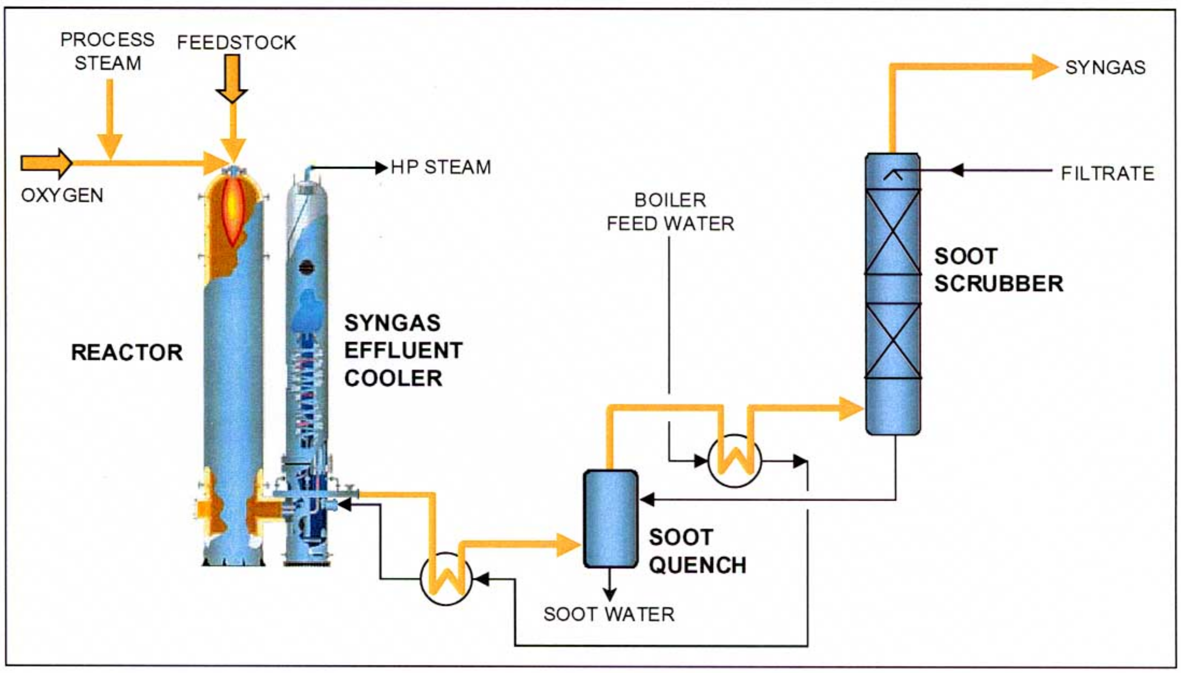
Source: Conoco Phillips

Shell Gasifier

The feed coal to the Shell gasifier is pulverized and dried with the same type of equipment used for conventional pulverized coal boilers. The heat for the dryer comes from combusting a small portion of the product syngas. From the dryer the coal is pressurized in lock hoppers and fed into the gasifier. The transport gas is usually nitrogen. Shell is a dry fed pressurized, upflow, entrained slagging gasifier. The gasifier is a waterwall encased pressure vessel. The syngas enters the syngas cooler to produce high pressure steam, in what amounts to a fire tube steam generator. This high pressure steam is utilized in both the gasification process as well as the steam bottoming cycle. Subsequently, particulates are removed by the hot/dry candle filters and are recycled to the gasifier. After additional cooling, the syngas is water scrubbed to remove chlorides, and passed through a catalyst to hydrolyze the COS so it can be removed in the Acid Gas Removal (AGR) train as H_2S.

Low sulfur gas from the AGR is preheated and sent to the power block. Acid Gas from the AGR is sent to the Claus plant and tail gas unit for maximum sulfur recovery. The oxygen enriched Claus plant is designed with both air and oxygen feeds.

Exhibit 3-6
Shell Gasifier System



Source: Shell

3.3 Moving Bed Gasifiers

There are two different commercial moving bed gasifiers, the Lurgi (Dry Ash) and the British Gas / Lurgi (BGL - ash slagging)

Lurgi (dry ash)

The Lurgi moving-bed, water-jacket, dry-bottom, high pressure (450 psi) gasifier has been used at SASOL (South Africa) and Great Plains (North Dakota) to produce hydrocarbon liquids and substitute nature gas (SNG), respectively. The Lurgi gasifier has counter-current coal and raw gas flow – coal flows down and raw gas rises, producing a dry ash at the bottom (~1800 °F, below the ash melting point) and a hot syngas (~900 °F) at the top. The methane-rich hot syngas is quenched to ~200 °F, which is further cooled to condense a raw gas liquor which contains tars, phenols and ammonia. After recovery of the byproducts, the stripped gas liquor can be used of cooling water. The Lurgi gasifiers use a lump coal and cannot tolerate:

- high percentage of fines – less than 10% less than ¼“
- high caking coal – plasticity of coal

The fixed/moving bed gasification processes have been used extensively to produce liquid fuels and SNG – but not in IGCC applications. The Lurgi (dry ash) gasifier has been in commercial operation since 1954 producing hydrocarbons and liquid fuels and synthetic/substitute natural gas (SNG).

British Gas/Lurgi (BGL – ash slagging)

British Gas began the development of the BG/L slagging, moving-bed gasifier in the early 1970s and had operated a 50 MW (equivalent) demonstration unit. The upper level was the conventional Lurgi fixed-bed gasifier (dry coal feed, raw gas quench and treatment), while the lower level incorporated the BG technology of steam and O_2 injection via tuyeres in the bottom of the gasifier, resulting in molten slag extraction. This allowed the use of a higher % of coal fines (up to 30% less than ¼“, compared to Lurgi dry ash), injected as a fine coal slurry thru the tuyeres. Early operation was with the coal fines briquetted with bitumen and blended with the lump/sized coal.

Due to the counter-current flow of coal (down) and gas (up), the exit gas temperature is low (~1,050 °F) compared to the other gasification processes, resulting in a significant amount of hydrocarbons in the syngas, including tars and oils. Raw gas is quenched with recycled aqueous liquids (~200 °F) and cooled, condensing the tars and oils. The condensed liquids are separated into a hydrocarbon fraction (recycled to the gasifier) and an aqueous fraction with NH_3 (used for gas quench). This results in a large "petrochem" operation to recovery and/or recycle the hydrocarbons liquids thru tuyeres (to extinction).

The BG/L gasification process was developed to produce a high methane content as an efficient gasifier to produce a substitute/synthetic natural gas (SNG). Two large gasification units were operated in England at the British Gas Westfield development Center in Fife, Scotland. This gasification technology is currently offered in the US by Allied Syngas Corporation.

3.4 Fluidized Bed Gasifiers

For various reasons, the fluid-bed gasifier has not been commercialized for IGCC. The primary fluid-bed gasification project was the Pinon Pine IGCC demonstration unit. Recently, a new type of gasifier has been in development – the “transport” reactor, based on the fluid catalytic cracking (FCC) process used in oil refineries. For this report, the “transport” reactor (a circulating fluid bed) will be considered a fluid-bed gasifier, since cyclones are required to return bed material to the reactor, like a fluid-bed gasifier.

Kellogg-Brown and Root (KBR)

The ~5 MW pilot unit at Southern’s Wilsonville facility is a dry-feed (coal + limestone), pressurized (240 psig), dry ash transport gasifier which has operated on both air and O_2. Like the fluid-bed gasifiers, the transport gasifier’s circulating bed is designed to handle low rank coals - high ash and high moisture. The commercial concept is for air operation for IGCC.

A 285 MW air-blown, pressurized IGCC unit firing sub-bituminous coal (PRB) is planned for Orlando Utilities’ Stanton station with a heat rate of 8400 Btu/kWhr. Since air is the oxidant, a calcium-based desulphurization system will have to be used to remove the H_2S as a gypsum waste. However, the published literature shows a sulfur recovery after low-temperature gas cooling – implying a conventional AGR/SRU. [5]

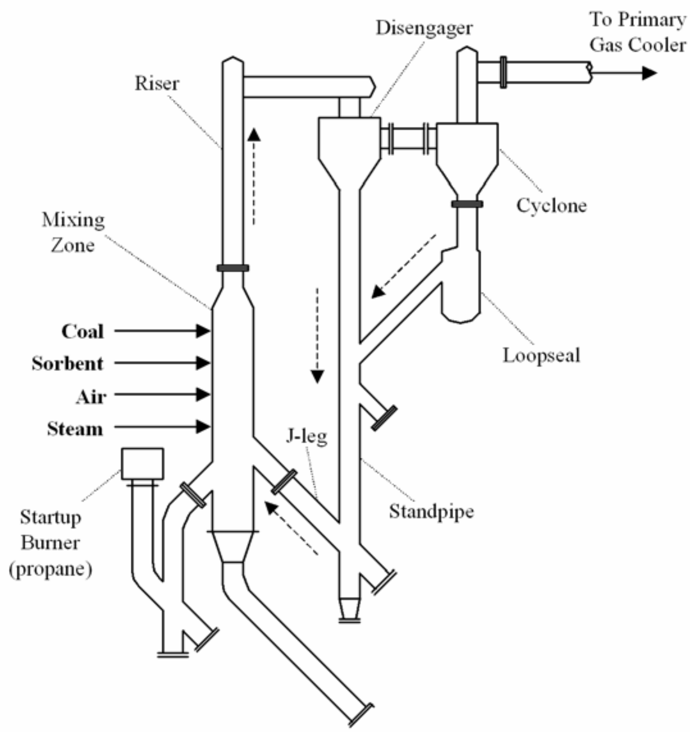
The KBR Transport gasifier is a circulating-bed reactor, which uses finely pulverized coal and limestone. Coal is dried, crushed, and fed to the single-train gasifier, through lock hoppers and pneumatic conveying systems.

The Transport gasifier consists of a mixing zone, a riser, a disengager, a cyclone, a standpipe, and a J-leg. The mixing zone is a relatively short, large diameter section at the bottom of the gasifier vessel. Dried and crushed coal, steam and air (or oxygen) are routed separately and introduced at the bottom of the mixing zone, where they mixed with solids from the standpipe. Most of gasification occurs in the riser, a smaller diameter section located directly above the mixer. All the feedstock is carried from the mixing zone into the riser and out of the reactor. The majority of the unreacted char-derived material leaving the riser is captured by disengager and cyclone assembly and recycled back to the mixing zone through the standpipe and a J-leg. [6]

Sintered metal HTHP filters are used to remove the residual char from the fuel gas. A small portion of the flow is removed, cooled and pressurized, and used as blowback gas to remove the char cake from the filter elements. Some syngas is also recycled back to gasifier to assist solids circulation. The dust-free syngas is piped to the gas cooling and acid gas removal sections prior to feed to the combustion turbine. The char collected by the HTHP filter and excess char from the recycle loop are cooled in screw coolers, where heat is transferred to the boiler feed water. Cooled char is mixed with water for dust suppression and sent to a landfill.

The fuel gas and residual char leaving the cyclone are cooled to 500ºF raising high-pressure steam. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

Exhibit 3-7
KBR Transport Gasifier



Source: [7]

Summary

All of the demonstrated commercial size IGCC units use the entrained-flow gasification process. They also do not produce any hydrocarbons liquids and produce an inert slag with high carbon conversion. As a result of the entrained-flow gasification IGCC demonstration units, there is extensive published literature on the process and equipment design and O&M.

Although there are specific issues with respect to each of the three major entrained flow gasifier designs, none of these technologies can be ruled out in the study on technical aspects.

3.5 Cost Comparison of PC with IGCC

Supercritical Pulverized Coal (PC) technology, along with environmental controls, is a proven method of generating electricity from coal. At Present, GE has stated that they expect the capital cost of their gasifier will be 20 - 25% more than a similar PC Unit. [8] GE has also stated that they expect to have this differential decrease as more units come on line. It should be noted that the capital cost of all types of power plants has been increasing due to global pressures on materials and labor. Xcel Energy expects to spend $1.35 billion for a proposed 750 MW expansion of an existing power station in Colorado, or $1800 per kW. [9] For Comparison, a grass-roots plant equivalent to the Wabash River Coal Gasification Repowering Project is reported to have a mid-year 2000 cost basis of EPC cost of 1,681 $/kW. [10] Since IGCC is still a technology in its early commercialization phase, there are more unknowns in the cost of a new unit that have different feedstock or other site/technology consideration from existing units.

Exhibit 3-8 below shows sample cost and performance for nominal 500 MW PC and IGCC power plants with two different coals. [11]

Exhibit 3-8
Cost, Performance and Economics for Nominal 500 MW Power Plants

	PC Subcritical	PC Super-critical	IGCC (E-Gas) W/ Spare	IGCC (E-Gas) No Spare	PC Subcritical	PC Super-critical	IGCC (E-Gas) W/ Spare	IGCC (E-Gas) No Spare
Fuel	PT #8 Coal	PT #8 Coal	PT #8 Coal	PT #8 Coal	IL #6 Coal	IL #6 Coal	IL #6 Coal	IL #6 Coal
Total Plant Cost, $/kW	1,230	1,290	1,350	1,250	1,290	1,340	1,440	1,330
Total Capital Requirement, $/kW	1,430	1,490	1,610	1,490	1,500	1,550	1,710	1,580
Fixed O&M, $/kW-yr	40.5	41.1	56.1	52.0	42.5	42.7	61.9	57.2
Variable O&M, $/MWh	1.7	1.6	0.9	0.9	2.9	2.7	1.0	1.0
Avg. Heat Rate, Btu/kWh (HHV)	9,310	8,690	8,630	8,630	9,560	8,920	9,140	9,140
Capacity Factor, %	80	80	80	80	80	80	80	80
Levelized Fuel Cost, $/MBtu (2003$)	1.50	1.50	1.50	1.50	1.00	1.00	1.00	1.00
Capital, $/MWh (Levelized)	25.0	26.1	28.1	26.0	26.1	27.2	29.9	27.7
O&M, $/MWh (Levelized)	7.5	7.5	9.2	8.6	9.0	8.8	9.8	9.1
Fuel, $/MWh (Levelized)	14.0	13.0	12.9	12.9	9.6	8.9	9.1	9.1
Levelized Total COE, $/MWh	46.5	46.6	50.2	47.5	44.7	44.9	48.8	45.9

Source: [12]

4 Power Plant

4.1 Combustion Gas Turbine

Traditionally the combustion turbines (CT) have been designed for natural gas (~950 Btu per scf LHV) operation – not for the relatively lower heating value syngas (~250 Btu per scf-LHV). The "C" in methane of natural gas needs the full stoichiometric amount of air; while the "CO" in syngas needs about half the stoichiometric air – therefore the air compressor of the CT has generally excess capacity on syngas. As the exhaust mass flow rate with syngas is significantly increased due to relatively lower heating value of the fuel and also due to the diluent injection requirements for NOx control, the power output on syngas is greater than on natural gas. The power output of a gas turbine typically decreases 3-4 % per 1,000 feet of elevation, resulting in a large decrease in output at high elevation. This will result in lower output from a similar cost IGCC plant at a higher elevation.

The salient differences between the natural gas and syngas operations of the combustion turbines are presented in the Performance Report.

Two major OEMs i.e, General Electric (GE) and Siemens are now offering Advanced Class Combustion Turbines for IGCC application with entrained flow gasifiers.

The GE "7FA" CT has continued to increase in size (MW, gross), firing temperature and pressure ratio (PR) to the "7FB".

- Natural Gas
  - 7F/7FA – 150 to 172 MW, 2300 to 2420 °F, Pressure Ratios up to 15.5:1
  - 7FB - 185 MW, 2500+ °F, Pressure Ratios up to 18.5:1.
- Syngas
  - 7F/7FA – 192 MW (syngas combustors and nozzles)
  - 7FA+e – 197 MW (higher temperatures and pressure ratio) listed at 210 MW.
  - 7FB – 232 MW (higher torque rotor, higher temperature and Pressure Ratios, advanced materials and seals), with constant output up to 80 °F – available in ~2007.

Based upon the recent successful testing of combustors in Germany, Siemens is now offering their SGT6-5000F (501F) combustion turbines for IGCC application. The combustion turbines are suitable for operation with Syngas as well as hydrogen fuel.

Siemens presented the following salient features of their SGT6-5000F combustion turbines with syngas operation at the 2006 Electric Power Conference in Atlanta.

- 232 Mw output at ISO. Output remains unchanged up to about 90°F ambient temperature.
- Operation suitable from (-) 30°F to 122°F and elevations to 7,550 ft.
- Natural gas and syngas cofiring between 30 – 100% load.
- Fuel transfer NG to SG or vice versa between 30 – 100% load
- Emissions:
  - On Syngas with diluent: NOx <= 15 ppmvd between 50 – 100% load, CO <=10 ppmvd between 70 – 100% load.
  - On Natural gas with diluent: NOx <= 25 ppmvd and CO <=10 ppmvd between 70 – 100% load.
- No changes in the compressor design. It is possible to have 0-50% air side integration with gasifier.
- Hot gas path component life and inspection intervals are same as that of natural gas application.
- RAM targets same as that of natural gas.
- Start up time to full load with natural gas: 10 minutes

Start up and Backup Fuel

Combustion Turbines for syngas application requires a start up fuel. Either gaseous (typically natural gas) or liquid fuel (No #2 oil) is used. The start-up fuel can also be used as a back-up to continue operation of the combined cycle unit to achieve a higher level of IGCC availability. Under a back-up scenario, the steam turbine output is reduced significantly due to the lack of steam generation in the gasifier. The typical backup fuel for IGCC is natural gas; therefore if natural gas is not available, reliability will be dependent on the gasifier and other plant systems including the ASU and AGR.

NOx Reduction in Turbine

A diluent is added to the syngas to lower the CT flame temperature to reduce thermal NOx. Diluents include:

- Nitrogen (N_2)
  - lowest specific heat (0.3) and expensive (highest form of energy – produced by electricity in ASU)

  - Requires additional HP :
  - Separate compressor to boost pressure (even from a high pressure ASU)

- Carbon Dioxide (CO_2) – higher specific heat than N_2 (0.6), but with CO_2 removal and recovery (for sequestration), there may not be CO_2 available
- Syngas Saturation
- Steam (high pressure - ~400 psig)
  - High specific heat like CO_2 (0.6), least expensive, but uses large amounts of steam (~25%)
  - With very deep sulfur removal (99.9+%) for H_2 and chemicals production or fuel cell, the dew point of the flue gas in the HRSG is lower. This will mean that more low level heat is available.

4.2 Heat Recovery Steam Generator (HRSG)

The heat recovery steam generator (HRSG) in a natural gas combined cycle (NGCC) unit with “F” class CTs is used to produce steam from the hot CT exhaust gas (~1100 °F). The NGCC’s HRSG has the same major functions as a PC boiler -economizer, evaporator and superheater. Unlike a PC boiler where only 1 pressure steam (HP) is produce in the boiler, a CC HRSG typically produces 3 pressure levels. IGCC’s HRSG has some differences from the HRSG in a NGCC unit.

A typical natural Gas HRSG contains the following:

- HP steam at 1800 -2400 psig and 1050 °F.
- Hot reheat steam at 500 -700 psig and 1050 °F.
- LP steam at 20 - 90psig and 500 °F.

A typical Integrated Gasification/Combined Cycle contains the following:

- Due to the high mass flow from the CT, there is more steam produced in the IGCC HRSG. In addition, the gasifier cooler also produces HP (typical 1800 psig) saturated steam that needs to be integrated in the HRSG superheater.
- HP – primary and secondary superheaters, an evaporator (partial) and high and low pressure economizers. The gasifier typically supplies over 50% of the HP saturated steam with all the HP steam being superheated in the HRSG. The water for the syngas cooler is supplied from the high temperature economizer

- LP – economizer, evaporator and superheater. The extra heat available in the HRSG is used to heat the feedwater (economizer) for the gasifier.

Typically the HRSGs in syngas fired IGCC application requires about 50% more superheater/reheater/HP economizer panels compared to natural gas fired CC plants.

The other issues specific for HRSGs in IGCC applications are:

- As syngas contains much higher level of sulfur compared to natural gas, the flue gas temperature at HRSG exit in IGCC application is significantly higher (230-270°F) than that (160 – 200°F) in NGCC application.

- Special considerations need to be given for SCR and down stream component design to avoid sulfur poisoning and Ammonium salt formation on downstream components. Quite often this requires provision for wide fin spacing and water washing.

- If HRSGs are to be designed for CT operation on back up fuel, this must be integrated in the HRSG design from the beginning due to significant changes in the duty requirements with back up fuel. The HRSG may require economizer bypass and additional desuperheating in the reheater /superheater sections for proper operation.

- Supplemental firing in HRSG is possible with either syngas or natural gas. However, the following factors need to be integrated in the design.

    - As the oxygen level in CT exhaust with syngas firing is typically 2-3% points lower than that of NGCC plant, augmenting air may be required for stable operation and emission controls.

    - The exhaust temperature, water and the CO_2 content of the turbine exhaust gas are the most influential in designing of the duct burner systems.

    - The turbine exhaust gas distribution, the variation in the exhaust gas temperatures (across the duct at the inlet to the burner) at different operating conditions, and the furnace length may also act as limiting factors.

    - The maximum amount of supplemental firing will be determined by the HRSG thermal design limitations with both syngas and back up fuel operation of the CT.

4.3 Steam Turbine

The IGCC steam turbine is a conventional NGCC steam turbine, tandem compound, 2 casing, 2 or 3 pressure reheat type designs with dual flow LP casing exhausting to a water or air cooled condenser. The LP casing is typically of down exhaust design.

The throttle flows and hence the output of the steam turbine in IGCC application are much higher than those of similar NGCC plant due to the integration with the gasifier plant.

The heat rejection system and all the supporting system in the power block are generally of higher capacity than those of NGCC plant of similar NGCC plant.

Unlike CT or HRSG, there are no special considerations for the steam turbine design.

5 Key Issues

5.1 Emissions

Although IGCC has been perceived as being environmentally superior to PC, this impression needs to be properly clarified:

SO_2/SO_3

The gasification process itself does not produce SOx. Rather sulfur is found primarily as hydrogen sulfide (H_2S) in the syngas, which is easily removed to very low levels by mature, proven acid gas removal technologies commonly used in the gas-processing and oil-refining industries. SOx is produced in the power island when the syngas is burned in the combustion turbine. There are four basic types of AGR systems: Physical solvents of which Selexol and Rectisol are typical examples, chemical solvents which include amines, Physical-chemical or mixed solutions such as Sulfinol, and finally oxidatative washes such as Sulferox and Crystasulf in which the H_2S is oxidized to elemental sulfur. IGCC applications use an amine or Selexol AGR to remove sulfur. The addition of COS hydrolysis (to H_2S) increases sulfur removal to greater than 99%, and over 99.5 % on high sulfur fuels. As the required sulfur removal increases, the cost and utilities required for the AGR also increase. The sulfur removal levels have not been proven in IGCC applications, but they have in other applications.

This is in contrast to PC Units where FGD can be designed for 98% SO_2 removal.

NOx

The gasification process itself does not produce NOx. Rather nitrogen is found primarily as ammonia (NH_3) in the syngas, which is easily removed in water-wash scrubbing. NOx is produced in the power island when the syngas is burned in the combustion turbine. As discussed above, NOx is reduced using diluent to 15 - 25 ppm in the HRSG exhaust. This would translate to 0.06 - 0.1 lb/MMBtu. If it is required to meet environmental requirements, SCR can be used to reduce NOx which could lower NOx by about 80%. However, SCR has not been used for Syngas applications. SCR is part of the proposed Southern Company Gasification facility near Orlando, Florida.

This is in contrast to PC units where SCR has been proven to lower NOx below 0.15 lb/MMBtu.

Mercury (Hg)

The mercury level in the fuel will be reduced by 90% or greater by an activated carbon bed from the trace levels contained in the fuel. Actual emissions levels will require mercury analysis for the design coal. Such a system has been successfully utilized at Eastman for years. [13]

In a PC unit, a more elaborate system is usually required to lower mercury levels below 90 %.

CO

CO is typically reduced using combustion controls on the gas turbine. Typical levels are 10 - 25 ppm in the HRSG exhaust. CO catalyst is not recommended if SCR is used to lower NOx.

Ammonium Bisulfate (ABS)

The Polk IGCC project reports on a concern with ABS deposits in the HRSG if SCR is added to the HRSG to meet lower NOx emissions. Recent GE presentation mentions deep sulfur removal for SCR in the HRSG – to avoid ABS. Therefore, an IGCC with an SCR will have to meet low sulfur requirements to minimize fouling in the HRSG. The precise applications and approaches to ABS formation in the HRSG with SCR are still being studied by the industry. However, several known AGR process can be applied to meet the requirements.

5.2 CO_2 Sequestration

In an IGCC application, CO_2 is most easily removed from the syngas stream as opposed to the fully combusted flue gas stream exiting the gas turbine. Proven acid gas removal technologies commonly used in the gas-processing and oil-refining industries can capture CO_2. CO_2 can be removed and concentrated using the same liquid solvents used to remove and concentrate H_2S from the syngas. In a typical IGCC application syngas is cooled just prior to entry into the acid gas removal process due to the low operating temperature of conventional liquid-solvent based acid gas removal processes. H_2S and CO_2 are removed at the same time utilizing the same process technology, the selection of which depends upon the sequestration requirements for the facility. CO_2 removal can be made more efficient and higher amounts of carbon can be captured if the syngas is processed in a shift reactor(s).

Water-gas shift (or shift) refers to the conversion of CO to H_2 through reaction of the CO with H_2O. The optimal location for CO_2 removal, from either a shifted or unshifted gas stream, is from a cool syngas stream. Cooling the syngas condenses water vapor which in turn helps elevate the CO_2 partial pressure.

In addition, the syngas will be hydrogen rich which will require modifications to the Gas turbine. There will be a reduction in capacity due to the heat loss in the shift reaction.

The CO_2 that is captured must be compressed and sequestered, typically in geological formations or in Enhanced Oil Recovery (EOR) application.

5.3 Byproducts

There are several byproducts from coal, including:

Sulfur

- PC can produce wall-board grade gypsum.
- IGCC produces elemental sulfur or sulfuric acid.

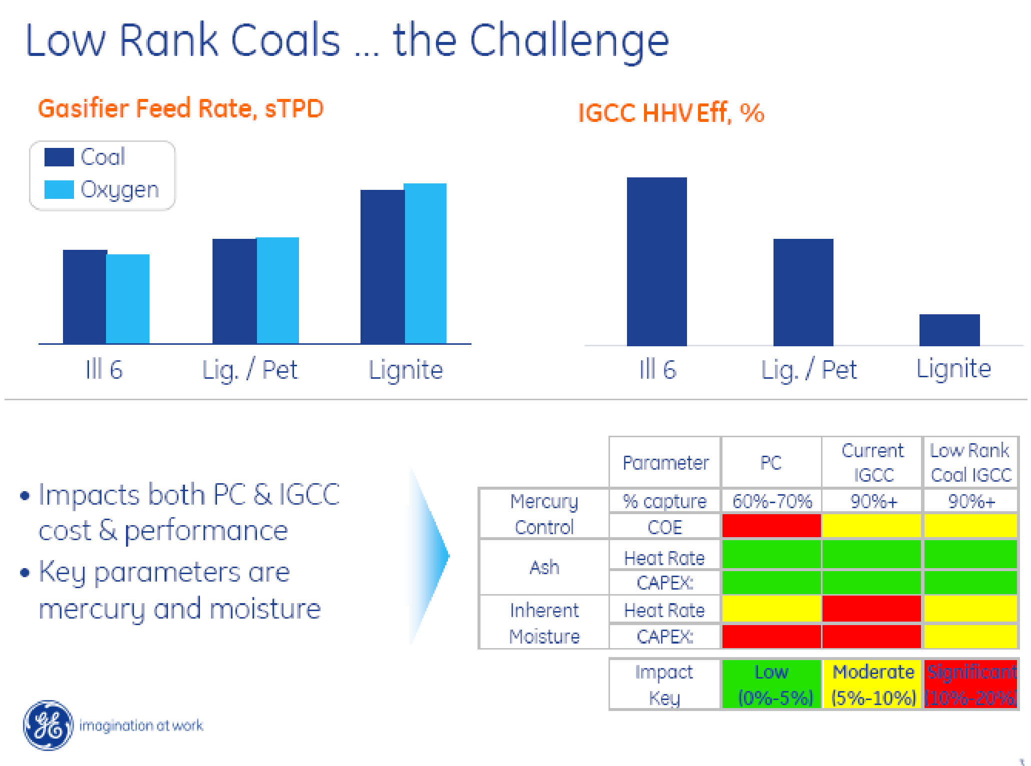
Ash / Slag

Many utilities sell PC's bottom ash and some sell fly ash. IGCC's slag (>90% of the ash) can also be marketed if the unburned carbon is low, which would be the case for entrained gasification technologies. These processes produce a vitreous, nontoxic, inert slag that has multiple product uses.

5.4 Alternate Coals

Gasifiers can be designed for a range of coals with a varied effect on performance as shown in Exhibit 5-1 below.

Exhibit 5-1
Low Rank Coal Performance



Source: [14]

5.5 Availability and Maintenance

IGCC's complexity (equivalent to an oil refinery) results in more components, and therefore a larger chance of component failure lowering plant reliability. This can result in more forced outages for an IGCC than a PC and therefore a lower availability.

Maintenance is a major function of forced outages – ie, the repair or replacement of equipment that results in forced outages. The following exhibits show typical availability for the Polk and Wabash gasifiers. The four commercial IGCC demonstration units have lower availability than expected by the electric utility industry.

Exhibit 5-2
Polk IGCC Availability Chart

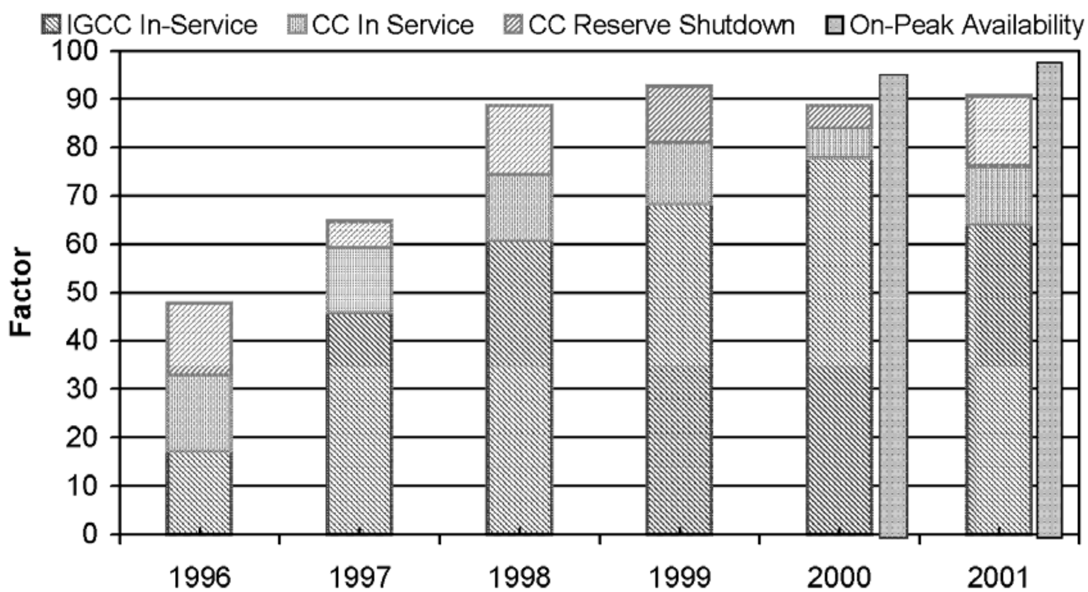
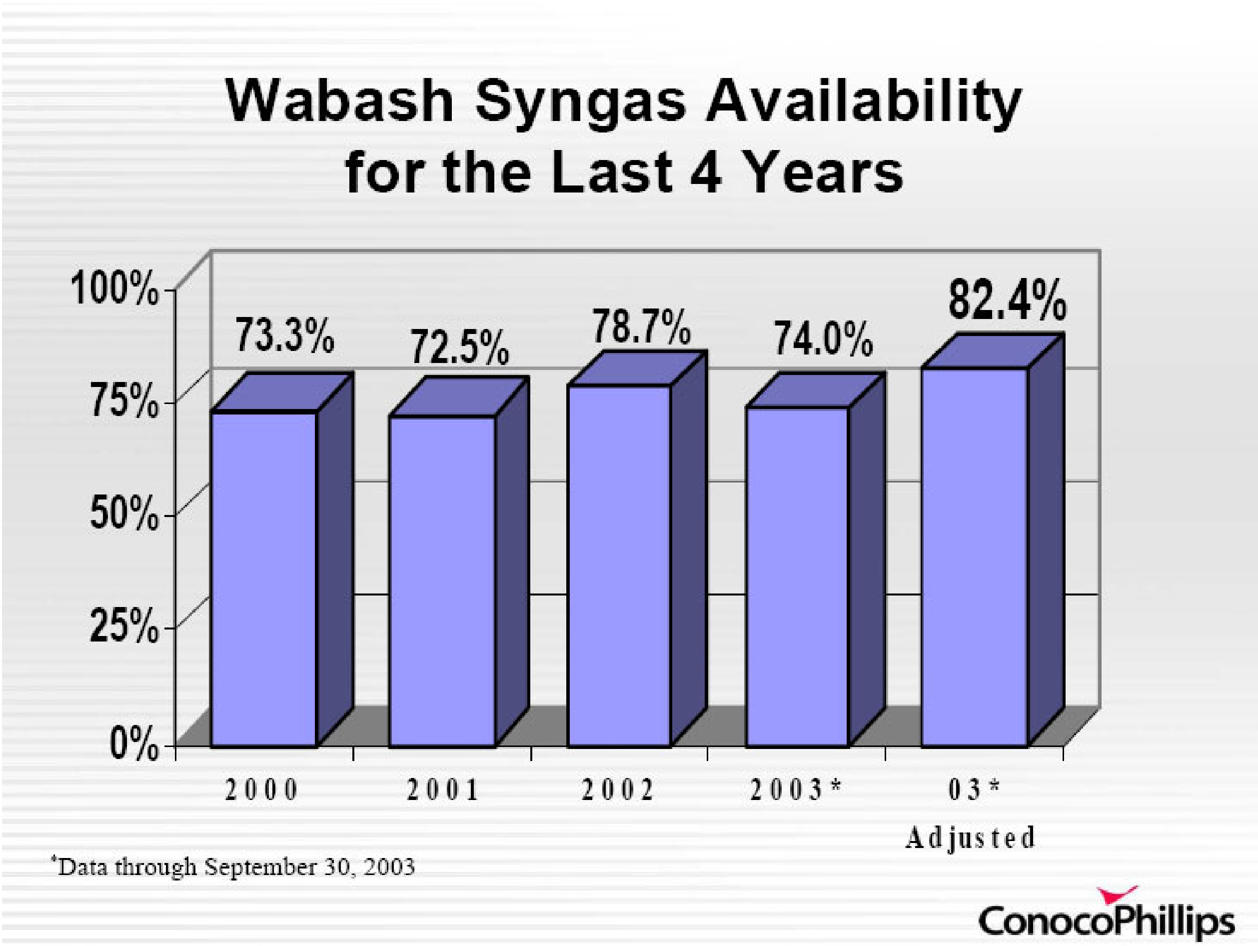


Exhibit 5-3
Polk IGCC Availability Table

	Gasifier In Service	IGCC In Service	Total In Service	Combined Cycle Availability	On-Peak Availability
1996	27.5	17.2	32.9	47.8	
1997	50.4	45.6	59.3	64.8	
1998	63.3	60.8	74.4	88.7	
1999	69.9	68.3	81.1	92.7	
2000	80.1	78.0	84.0	88.7	94.9
2001	65.4	64.2	76.1	90.6	97.7

Source: [15]

Exhibit 5-4
Wabash Gasifier Availability



Source: [16]

High coal gasification availability has been achieved by TN Eastman, about a 1% forced outage rate. However, Eastman has a full spare gasifier (1 + 1), switches the gasifiers every 30 to 60 days and performs extensive maintenance on off-line gasifier. Therefore, high IGCC availability can be achieved with a spare gasifier and an extensive maintenance program.

The low 80s% availability for the existing IGCC demonstration units is misleading. The next round of IGCC demonstration units will have implemented design or operating solutions for most of the equipment and operational problems that resulted in forced outages during the operation of the existing demonstration units. Therefore, the next round of IGCC demonstration units will have higher availability and should be able to achieve at least 85%, without a spare gasifier. Shell expects the target availability to be lower initially and gradually improve to about 90% without a spare gasifier. In their view, their availability target can be met after three years of operation. Unfortunately, units with these improvements have not yet been started up. Therefore their reliability and performance cannot be confirmed.

The existing IGCC units went through a long start-up and debugging period, much longer than a mature PC plant. Each of the components of an IGCC plant may have been tested individually, but the degree of integration of the new systems can result in a longer start-up. As more units come on line, the reliability will be demonstrated such that comparisons with PC can be made based on operating data.

6 References

[1] DOE Worldwide Gasification Database.

[2] "Energy Policy Act of 2005: Potential Value of Incentives for IGCC Deployment" Tom Wilson - EPRI, Presented at the Gasification Technologies Conference 2005 San Francisco, California October 9 -12, 2005

[3] "Gasification Process Selection – Trade-offs and Ironies", Neville Holt – EPRI, presented at the Gasification Technologies Conference 2004, October 3-6, 2004, Washington DC.

[4] "The IGCC Reference Plant", Robert Rigdon, GE Energy Presentation at the Gasification Technologies Conference 2005 San Francisco, California 11 October 2005.

[5] "KBR Transport Gasifier", Peter V. Smith, Gasification Technologies Conference 2005 San Francisco, California October 9 -12, 2005

[6] "The PSDF – Commercial Readiness for Coal Power – Revisited", Roxann Leonard, Tim Pinkston, Luke Rogers, Randall Rush (all Southern Company Service, Inc.), and John Wheeldon (EPRI), Pittsburgh Coal Conference, Pittsburgh, PA, 9/23-27/2002.

[7] "Development Status of the Transport Gasifier" Roxann Leonard, Luke Rogers, P. Vimalchand, Guohai Liu (all Southern Company Service, Inc.), Peter V. Smith (Kellogg Brown & Root, Inc.) and James Longanbach (National Energy Technology Laboratory), KBR Paper # 1707 Gasification Technologies 2001 San Francisco, California October 7-10, 2001.

[8] "GE's Gasification Developments" Edward Lowe, General Manager, GE Gasification Presented at the Gasification Technologies Council October 10, 2005

[9] "Is the widely accepted cost gap for IGCC and PC plants myth or reality?" Harry Jaeger, Gas Turbine World: July-August 2005.

[10] "Gasification Plant Cost and Performance Optimization- Final Report" Contract No. DE-AC26-99FT40342, U. S. Department of Energy National Energy Technology Laboratory (NETL) September 2003.

[11] "Pulverized Coal and IGCC Plant Cost and Performance Estimates" George Booras and Neville Holt - EPRI, presented at the Gasification Technologies Conference 2004, October 3-6, 2004, Washington DC.

[12] "Pulverized Coal and IGCC Plant Cost and Performance Estimates" George Booras and Neville Holt - EPRI, presented at the Gasification Technologies Conference 2004, October 3-6, 2004, Washington DC.

[13] "Coal Gasification: What are You Afraid of" POWER-GEN International Conference 2004 November 30 – December 2, 2004, Nathan Moock and William Trapp of Eastman Gasification Services Company

[14] " Gasifying Low Rank Coals" DeLome Fair, GE Energy Gasification Technologies Council October 11, 2005

[15] "Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project Final Technical Report" Contract No. DE-FC-21-91MC27363, U. S. Department of Energy National Energy Technology Laboratory (NETL) August 2002.

[16] "Cost & Performance of Current IGCC Offering" Phil Amick, ConocoPhillips Workshop on Gasification Technologies June 8-9, 2004.

Field Testing of Mercury Control Technologies for Coal-Fired Power Plants

by Thomas J. Feeley, III[1.], Lynn A. Brickett[1.], B. Andrew O'Palko[1.], and James T. Murphy[2.]

[1.] U.S. Department of Energy, National Energy Technology Laboratory
[2.] Science Applications International Corporation

The U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) is conducting a comprehensive research, development, and demonstration (RD&D) program directed at advancing the performance and economics of mercury control technologies for coal-fired power plants. The program also includes evaluating the fate of mercury in coal by-products and studying the transport and transformation of mercury in power plant plumes. This paper presents results from ongoing full-scale and slip-stream field testing of several mercury control technologies and approaches and plans for future testing.

INTRODUCTION

On March 15, 2005, the U.S. Environmental Protection Agency (EPA) issued a final regulation for the control of mercury emissions from coal-fired power plants.[1] The Clean Air Mercury Rule (CAMR) establishes a nationwide cap-and-trade program that will be implemented in two phases and applies to both existing and new plants. The first phase of control begins in 2010 with a 38 ton mercury emissions cap based on "co-benefit" reductions achieved through further sulfur dioxide (SO_2) and nitrogen oxides (NOx) emission controls required under EPA's recently issued Clean Air Interstate Rule (CAIR). The second phase of control requires a 15 ton mercury emissions cap beginning in 2018. It has been estimated that U.S. coal-fired power plants currently emit approximately 48 tons of mercury per year.[2] As a result, the CAMR requires an overall average reduction in mercury emissions of approximately 69% to meet the Phase II emissions cap.

Previous testing has demonstrated that some degree of mercury co-benefit control is achieved by existing conventional air pollution control devices (APCD) installed for removing NOx, SO_2, and particulate matter (PM) from coal-fired power plant combustion flue gas. However, the capture of mercury across existing APCDs can vary significantly based on coal properties, fly ash properties (including unburned carbon), specific APCD configurations, and other factors, with the level of control ranging from 0% to more than 90%. Mercury is present in the flue gas in varying percentages of three basic chemical forms: particulate-bound mercury, oxidized mercury (primarily mercuric chloride – $HgCl_2$), and elemental mercury. The term *speciation* is used to describe the relative proportion of the three forms of mercury in the flue gas. Mercury speciation has a large affect on co-benefit mercury control of existing APCDs. For example, elemental mercury is not readily captured by existing APCD, while particulate-bound mercury is captured by electrostatic precipitators (ESP) and fabric filters (FF). Oxidized mercury is water-soluble and therefore readily captured in flue gas desulfurization (FGD) systems. The use of selective catalytic reduction (SCR) for NOx control has shown to be effective in converting elemental mercury to oxidized mercury that can be subsequently captured in a downstream FGD absorber.[3] In general, plants burning subbituminous and lignite coals demonstrate significantly lower mercury capture than similarly equipped bituminous-fired plants. The lower performance observed for these low-rank coals has been linked to higher levels of elemental mercury, associated with the coal's low chlorine content. Table 1 presents a summary of average co-benefit mercury capture for various APCD configurations and coal rank based on testing conducted by the EPA in 1999.

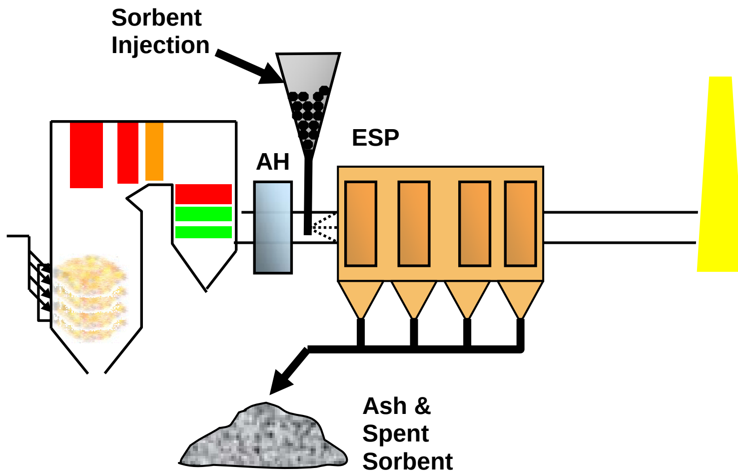
Table 1 – Average Mercury Capture by Coal Rank and APCD Configuration

APCD Configuration	Average Percentage Mercury Capture		
	Bituminous	Subbituminous	Lignite
CS-ESP	36	3	- 4
HS-ESP	9	6	NA
FF	90	72	NA
PS	NA	9	NA
SDA + ESP	NA	35	NA
SDA + FF	98	24	0
SDA + FF + SCR	98	NA	NA
PS + Wet FGD	12	- 8	33
CS-ESP + Wet FGD	74	29	44
HS-ESP + Wet FGD	50	29	NA
FF + Wet FGD	98	NA	NA

CS-ESP = cold-side ESP
HS-ESP = hot-side ESP
PS = particulate scrubber
SDA = spray dryer adsorber

Although conventional APCD technology can capture some mercury, new mercury control technologies will be needed to help achieve the level of control necessary to meet the CAMR Phase II mercury emission cap. To date, use of activated carbon injection (ACI) has shown the most promise as a near-term mercury control technology. In a typical configuration, powdered activated carbon (PAC) is injected downstream of the plants' air heater and upstream of the particulate control device – either an ESP or FF (Figure 1). The PAC adsorbs the mercury from the combustion flue gas and is subsequently captured along with the fly ash in the ESP or FF. Although initial field testing of ACI has been relatively successful, additional RD&D is required before it is considered a commercial technology for coal-fired power plants. For example, the effect of long-term use of PAC (or any other injected sorbent or additive) on plant operations has yet to be determined. In addition, for plants that sell their fly ash, an increase in carbon content (or the addition of other chemical compounds) may adversely affect its sale and lead to increased cost for disposal.

Figure 1 – Activated Carbon Injection Technology Schematic



More recently, field testing has begun on a number of alternative approaches to enhance ACI mercury capture performance for low rank coal applications, including: 1) the use of chemically-treated PACs that compensate for low chlorine concentrations in the combustion flue gas; and 2) coal and flue gas chemical additives that promote mercury oxidation. In addition to ACI, other mercury control technologies are being tested to enhance mercury capture for plants equipped with wet FGD systems. These FGD-related technologies include: 1) coal and flue gas chemical additives and fixed-bed catalysts to increase levels of oxidized mercury in the combustion flue gas; and 2) wet FGD chemical additives to promote mercury capture and prevent re-emission of previously captured mercury from the FGD absorber vessel. These approaches are discussed in more detail in later sections. Additional research is needed on all of these mercury control technologies so that coal-fired power plant operators eventually have a suite of control options available in order to cost-effectively comply with the CAMR.

DOE/NETL's MERCURY RD&D PROGRAM

Recognizing the potential for mercury regulation, DOE/NETL has been carrying out comprehensive mercury research under the DOE Office of Fossil Energy's Innovations for Existing Plants (IEP) program.[4] Working collaboratively with power plant operators, the Electric Power Research Institute (EPRI), academia, state and local agencies, and EPA, the program has greatly advanced our understanding of the formation and capture of mercury from coal-fired power plants. Continued RD&D is necessary in order to bring advanced mercury control technology to the point that it is ready for commercial demonstration. Initial efforts in the early 1990s were directed at characterizing power plant mercury emissions and focused on laboratory- and bench-scale control technology development. The current program is directed at slip-stream and full-scale field testing of mercury control technologies, as well as continued bench- and pilot-scale development of novel control concepts. The near-term goal is to develop mercury control technologies that can achieve 50-70% mercury capture at costs 25-50% less than baseline estimates of $50,000-$70,000/lb of mercury removed. These technologies would be available for commercial demonstration by 2007 for all coal ranks. The longer-term goal is to develop advanced mercury control technologies to achieve 90% or greater capture that would be available for commercial demonstration by 2010.

MERCURY CONTROL TECHNOLOGY FIELD TESTING

DOE/NETL initiated pilot-scale slip-stream and full-scale field testing of mercury control technologies in 2001. While the scale of testing is large, this is still viewed as an R&D activity, rather than a commercial demonstration. Phase I field testing included an evaluation of ACI at four power plants during 2001-04. These tests included use of conventional commercially-available activated carbon sorbents. In addition, a proprietary chemical additive to improve mercury capture in wet FGD systems was evaluated at two other power plants. In further support of the near-term program goal, DOE/NETL selected eight new projects in September 2003 to test and evaluate mercury control technologies under a first round Phase II (Phase II-1) solicitation. Building on promising advances that resulted from Phase I activities, these projects focus on longer-term, large-scale field testing on a broad range of coal-rank and APCD configurations. These tests are providing important information on mercury removal effectiveness, cost, and the potential impacts on plant operations including by-product characteristics. Phase II-1 testing was initiated in 2004 and should be completed in 2006. In October 2004, DOE/NETL awarded a second round of six additional Phase II projects (Phase II-2). These projects will begin in 2005 and are scheduled for completion in 2007. Previous pilot- and full-scale testing has demonstrated that the low chlorine concentrations of most low-rank coals is a major limiting factor in the mercury control performance of conventional activated carbons. As a result, several of the Phase II projects include testing of chemically-treated activated carbons or oxidation additives that compensate for the lack of naturally-occurring chlorine (or other halogens) levels in the combustion flue gas. The Phase II testing also includes evaluation of non-carbon sorbents and oxidation catalysts. In addition, Phase II includes testing sorbents at several power plants with either low specific collection area (SCA) cold-side ESPs or hot-side ESPs – both of which can be difficult ACI applications. Table 2 presents a matrix of the Phase II projects by coal rank and APCD configuration. DOE/NETL is also planning to issue a Phase III solicitation in June 2005 to conduct additional long-term field testing of mercury control technologies capable of 90% or greater mercury capture. Project awards should be announced by February 2006. The following sections present a brief description of the Phase I and II projects and a summary of test results where available.

Table 2 - Phase II Mercury Control Field Testing Technology Matrix

Coal Rank	Cold-side ESP (low SCA)	Cold-side ESP (medium or high SCA)	Hot-side ESP	TOXECON	ESP/FGD	SDA/FF or SDA/ESP
Bituminous	Miami Fort 6	Lee 1	Cliffside	Independence	Yates 1	
		Lee 3	Buck	Gavin	Yates 1	
	Yates 1&2	Portland			Conesville	
					Conesville	
		Monroe				
Subbituminous	Crawford	Meramec	Council Bluffs			Holcomb
		Dave Johnston	Louisa			Laramie River
		Stanton 1	Will County			
Lignite (North Dakota)		Leland Olds 1			Milton Young	Antelope Valley 1
		Leland Olds 1				Stanton 10
						Stanton 10
Lignite (Texas)					Monticello	
					Monticello	
					Monticello	
Blends		St. Clair		Big Brown		

Sorbent Injection
Sorbent Injection & Oxidation Additive
Oxidation Additive
Oxidation Catalyst
Chemically-treated sorbent
Other – MERCAP, FGD Additive, Combustion

PHASE I FIELD TESTING (2001-04)

Full-Scale Testing of Mercury Control via Sorbent Injection

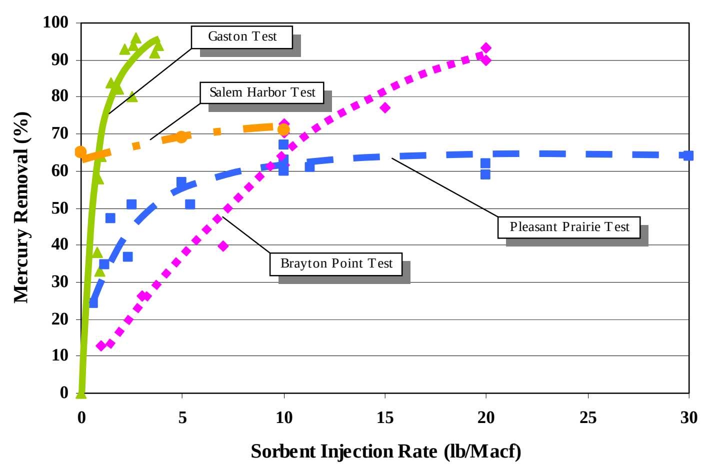
ADA Environmental Solutions (ADA-ES) conducted large-scale field tests at the four coal-fired plants described in Table 3. Results from this testing have been published previously.[5,6,7,8,9] The following is a brief summary of these results. Testing included parametric tests using several commercially available powdered activated carbon (PAC) products at various feed rates and operating conditions, followed by a one- to two-week long-term test with a PAC selected from the parametric testing. Figure 2 presents an overall comparison of the mercury removal versus PAC injection rate at the four plants. As Figure 2 suggests, the level of mercury reduction and PAC injection rate can vary significantly based on APCD configuration, coal rank, as well as baseline level of mercury reduction co-benefits. The following is a brief summary of the test results for each plant.

Table 3 –Phase I Field Test Sites for Activated Carbon Injection

Company	Plant	Coal Rank	APCD Configuration	Test Completed
Alabama Power	E.C. Gaston	Low sulfur bituminous	Hot-side ESP and COHPAC	April 2001
We Energies	Pleasant Prairie	Subbituminous	Cold-side ESP	November 2001
PG&E	Brayton Point	Low sulfur bituminous	Cold-side ESP	August 2002
PG&E	Salem Harbor	Low sulfur bituminous	Cold-side ESP and SNCR	November 2002

E.C.Gaston- The Gaston Plant is equipped with a hot-side ESP and a downstream pulse-jet fabric filter (PJFF) baghouse. The retrofit of a high air-to-cloth ratio PJFF downstream of an ESP to improve particulate collection performance was developed by EPRI and is known as a compact hybrid particulate collector (COHPAC^{TM}) system. Baseline measurements indicated less than 10% mercury capture across the PJFF. Average PJFF inlet mercury concentration was approximately 11 microgram per dry normal cubic meter (µg/dncm), and 40% was elemental mercury. PAC was injected upstream of the PJFF during ACI testing. While there was no measurable performance difference between the PACs used during the parametric testing, Norit's DARCO Hg (formerly known as DARCO FGD) activated carbon was selected for the nine-day, long-term test. Mercury capture averaged 87–90% with a PAC injection rate of 1.5 pounds per million actual cubic feet (lb/MMacf) of flue gas based on three Ontario Hydro test results. However, mercury continuous emissions monitor (CEM) data indicated an average capture of 78% that varied from 36-90%. The use of a fabric filter enhanced ACI performance compared to the other test sites that used an ESP for particulate collection. However, as a result of the increased particulate loading during ACI, the required cleaning

Figure 2 – Phase I ACI Test Results



frequency of the PJFF significantly increased. This led to a concern of possible premature failure of the filter bags that could pose a reliability problem under long-term ACI operation. There was no improvement in mercury capture using a water spray cooling system to lower flue gas temperature.

E.C. Gaston – Extended Long-Term Testing. A one-year long-term performance evaluation of the impact of ACI on the PJFF was conducted at E.C. Gaston Unit 3 beginning in April 2003. The long-term testing included six-month ACI operation with the existing filter bags and six-month ACI operation with new high-permeation filter bags. The high-permeation filter bags were tested in order to reduce pressure drop across the bags and therefore reduce bag cleaning frequency during ACI, which was a concern during the earlier Phase I testing conducted in 2001. Baseline test conditions in April 2003 were significantly different than in April 2001: 1) higher PJFF cleaning frequency; 2) large variation (0-90%) in baseline mercury removal (compared to less than 10% in 2001); and 3) higher carbon content in the PJFF hopper ash. Average mercury removal was 86% at 0.55 lbs/MMacf PAC injection rate during the July-November 2003 long-term testing using the original filter bags. The new high-permeation bags were installed in December 2003 and initial baseline testing indicated a significant reduction in cleaning frequency from 4.4 pulses per bag per hour (p/b/h) to less than 1 p/b/h. Baseline mercury removal varied from 0-95%. The long-term testing of the high-permeation bags was started in January 2004 with a target PAC injection rate of 1.3 lb/MMacf and a bag cleaning frequency of 1.0 p/b/h. Results from the first two weeks indicated an average mercury removal greater than 90%. Unfortunately, the long-term testing was interrupted by a two-month outage on Unit 3. A second round of baseline testing was conducted after unit start-up in April 2004 during which mercury removal varied from 0-83%. The high-permeation bag long-term testing was then resumed for one month in May 2004. Average mercury removal was greater than 90% with a PAC injection feed rate of 1.3-1.6 lb/MMacf. The loss-on-ignition (LOI) levels of the fly ash, which serves as a measure of unburned carbon, was relatively high in 2003-04. This resulted in higher baseline co-benefit mercury removal and more frequent filter bag cleaning. The year-to-year change in operating conditions and resultant change in ACI performance at Gaston serve as a good example for why the results of short-term testing may not be reflective of long-term performance at either the test site or other similarly designed plants.

Pleasant Prairie. ACI mercury capture performance was limited on this subbituminous coal-fired plant compared to the other test sites that burned bituminous coal. Baseline measurements indicated less than 10% mercury capture across the ESP. Average ESP inlet mercury concentration was approximately 17 µg/dncm and 70-85% of it was elemental mercury. Norit's DARCO Hg activated carbon was used during the three five-day, long-term tests at PAC feed rates of 1.6-11.3 lb/MMacf, with mercury capture ranging from 46-66% based on CEM test results. Although ACI did not deteriorate ESP performance, the ESP was relatively large (468 ft^2/1000 acfm specific collection area, SCA) and additional testing needs to be conducted on units with smaller ESPs. However, the PAC in the fly ash rendered the ash unsuitable for sale as a supplement for Portland cement in concrete. As in the Gaston testing, there was no improvement in mercury capture using a spray cooling system.

Brayton Point. The Brayton Point Plant is equipped with two cold-side ESPs in series. During baseline testing the average mercury removal ranged from 30-90% across both ESPs and 0-10% across the second ESP. Average mercury concentration at the inlet to the first ESP was approximately 6 µg/dncm, of which 85% was particulate-bound and 5% elemental mercury.

Norit's DARCO Hg was injected between two cold-side ESPs at feed rates of 3-20 lb/MMacf, with mercury capture ranging from 25-90%, respectively, across the second ESP. The carbon injection did not deteriorate ESP performance. However, the second ESP was relatively large (403 SCA) and additional testing needs to be conducted on units with smaller ESPs.

Salem Harbor. This plant burns a South American bituminous coal that is not typical for U.S. power plants. During baseline testing average mercury capture across the ESP was approximately 90%. Average mercury concentration at the inlet to the ESP was approximately 10 μg/dncm of which 95% was particulate-bound mercury. The high baseline mercury removal was attributed to high levels of unburned carbon (25-30% LOI) and low flue gas temperature (~270 ºF). During parametric testing, baseline mercury removal decreased from approximately 90% to 20% while flue gas temperature was increased from 270°F to 350°F. A maximum mercury capture of only 45% was achieved at 350 °F during ACI with DARCO Hg at 20 lb/MMacf. While increasing temperature clearly caused a decrease in baseline mercury capture, the effect that increased temperature has on ACI performance is uncertain.

Enhanced Mercury Control in Wet FGD

There is evidence that a portion of the oxidized mercury captured in a wet FGD absorber can be reduced to elemental mercury and emitted out the stack. A method to prevent the reduction of oxidized mercury would enhance the overall mercury capture across the wet FGD system. Babcock & Wilcox and McDermott Technology Inc. carried out full-scale field tests of a proprietary liquid reagent to enhance mercury capture in coal-fired plants equipped with wet FGD systems.[10] The project was initiated in 2000 and completed in 2002. Testing was conducted at two power plants: Michigan South Central Power Agency's 60-MW Endicott Station and Cinergy's 1300-MW Zimmer Station. Both plants burn high-sulfur bituminous coal and use cold-side ESPs for particulate control. The Endicott Station uses a limestone wet FGD system with in situ forced oxidation and the Zimmer Station uses a magnesium-enhanced lime wet FGD system with ex situ forced oxidation.

Test results were mixed, with a favorable outcome at Endicott in that the reagent was able to suppress mercury reduction across the wet FGD system. Testing at Zimmer did not achieve the desired effect and reduction of oxidized mercury to elemental mercury continued across the wet FGD system during reagent usage. Possible explanations for the poor results at Zimmer include the higher sulfite concentration and lower liquid-to-gas ratio in the magnesium-enhanced lime wet FGD system, which may have impeded the reagent performance.

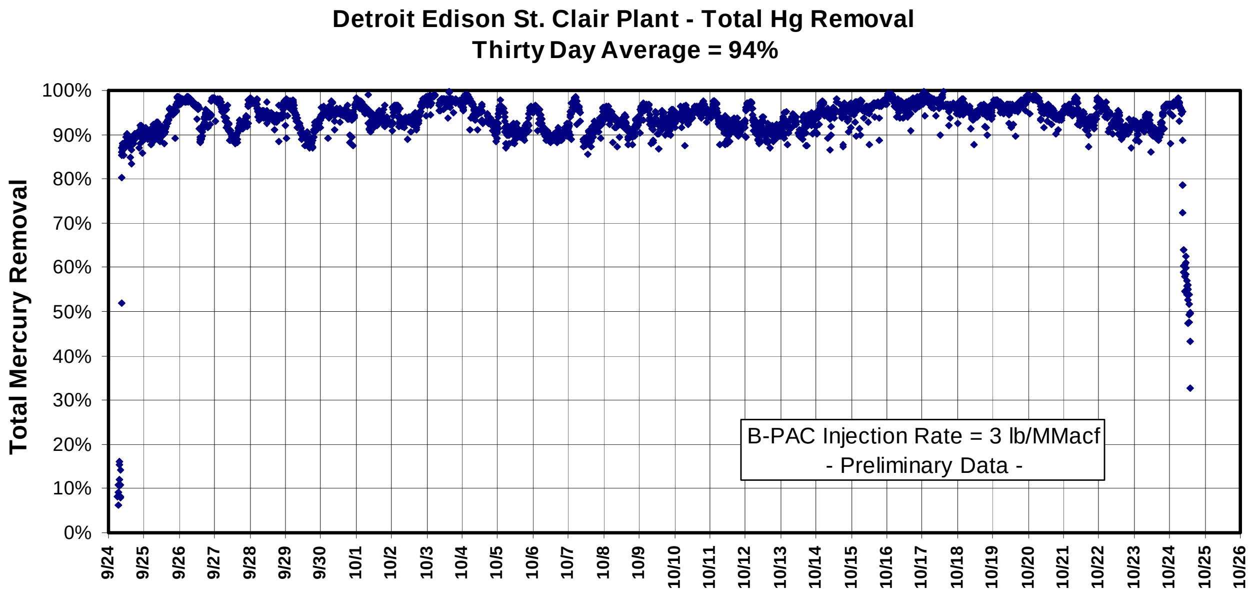
PHASE II, ROUND 1 FIELD TESTING (2004-06)

Chemically-Treated PAC

Sorbent Technologies Corporation is testing brominated-PACs that can be used as a cost effective alternative to conventional PACs for mercury capture in both cold-side and hot-side ESP applications.[11,12] A short-term trial was conducted at Duke Energy's Cliffside Plant that is equipped with a hot-side ESP. Long-term testing is being conducted at two plants.

St. Clair. Detroit Edison's 80 MW St. Clair Station burns a blend of 85% PRB and 15% bituminous coal and is equipped with an ESP (700 SCA). Testing was completed fourth quarter 2004. Baseline mercury removal across the ESP varied from 0-40%. Mercury concentration at the ESP inlet varied from 4-10 μg/dncm of which 80-90% was elemental mercury. Average mercury removal during the one-month long-term test was 94% using a brominated PAC (B-PAC™) at 3 lb/MMacf (Figure 3).

Figure 3 - St. Clair ACI Long-Term Test Results



Buck. Duke Energy's 140 MW Buck Plant burns low-sulfur bituminous coal and is equipped with a hot-side ESP (240 SCA). Testing is scheduled to begin second quarter 2005.

Chemically-Treated PAC and Additives

ADA Environmental Solutions (ADA-ES) is evaluating the use of chemically treated PACs and chemical additives to capture mercury for a variety of coal and APCD configurations at five power plants.[13,14]

Holcomb. Sunflower Electric's 360 MW Holcomb Station burns PRB subbituminous coal and is equipped with a spray dryer absorber and fabric filter baghouse (SDA/FF). Testing was completed third quarter 2004. Baseline mercury capture was only 13% across the SDA/FF while burning 100% PRB coal. SDA inlet mercury concentration was 11.7 µg/dncm and was almost 100% elemental mercury. Three methods for mercury control were evaluated during parametric testing - coal blending, ACI, and ACI combined with a coal additive to promote mercury oxidation. Blending 15% western bituminous coal with the PRB increased mercury capture to almost 80% (Figure 4). The mercury concentration of the western bituminous coal was similar to the PRB, but the chlorine concentration was higher (106 µg/g vs. 8 µg/g). Three sorbents were evaluated during the ACI parametric testing: 1) Norit DARCO Hg – a conventional PAC; 2) Calgon 208CP - a highly activated, but untreated PAC; and 3) Norit DARCO Hg-LH – formerly known as DARCO FGD E-3 – a brominated PAC. Mercury removal was approximately 50% with both the DARCO Hg and 208CPA untreated PACs at a feed rate of 1.0 lb/MMacf. However, the DARCO Hg-LH brominated PAC achieved 77% mercury capture at only 0.7 lb/MMacf and greater than 90% at 4.3 lb/MMacf. A proprietary chemical coal additive, ALSTOM Power's KNX, increased mercury removal from 50% to 86% when used with DARCO Hg at 1.0 lb/MMacf. The KNX additive decreased the percentage of elemental mercury at the SDA inlet to 20-30%. However, there was no improvement in mercury capture using the KNX without ACI. The DARCO Hg-LH was selected for further evaluation during a 30-day long-term test and was injected at 1.2 lb/MMacf with average mercury removal of 93% (Figure 5). No adverse balance-of-plant impacts were observed during the long-term testing. In particular, no excess levels of bromine were measured in the flue gas.

Figure 4 Holcomb Station Parametric Test Results with Coal Blending

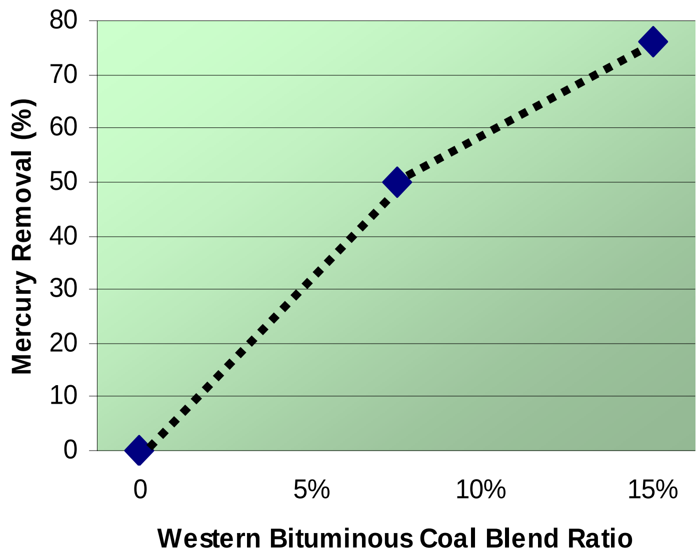
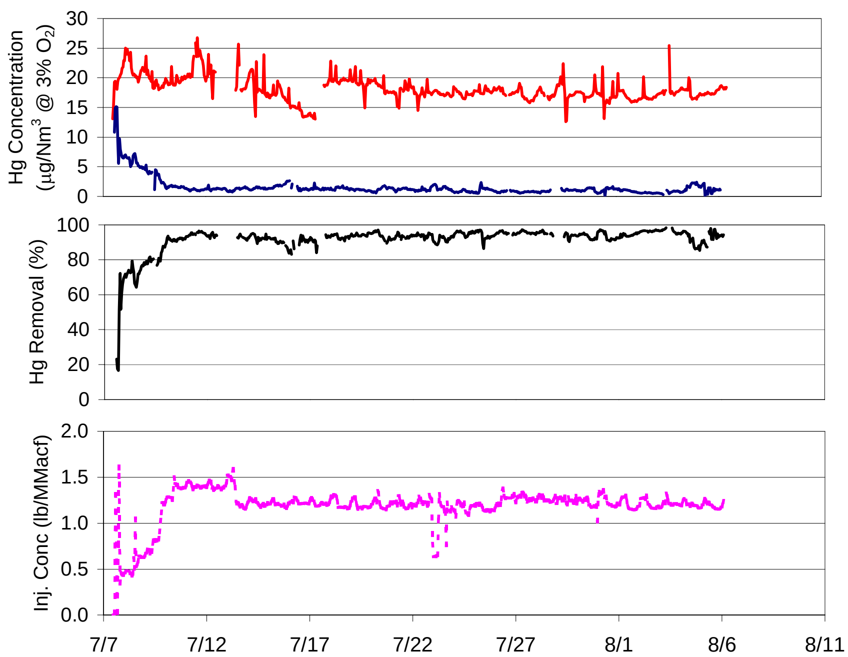
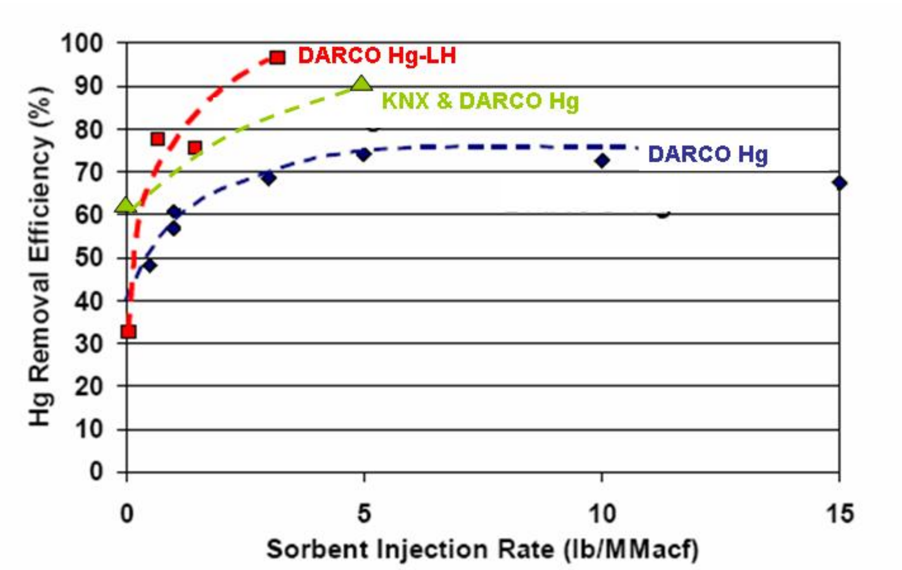


Figure 5 – Holcomb Station ACI Long-Term Test Results



Meramec. AmerenUE's 140 MW Meramec Station Unit 2 burns PRB coal and is equipped with an ESP (320 SCA). Testing was completed fourth quarter 2004. Baseline mercury capture across the ESP ranged from 15-18% with an inlet mercury concentration of approximately 8.5 µg/dncm while burning 100% PRB coal. During the parametric and long-term testing Unit 2 experienced a mill outage that resulted in variations of LOI that may have contributed to higher levels of particulate-bound mercury and consequently higher than normal baseline mercury removal. For example, during long-term testing the percentage of particulate-bound mercury was approximately 30%. Two methods for mercury control were evaluated during parametric testing - ACI and KNX with and without ACI. Norit DARCO Hg and Hg-LH sorbents were evaluated during the ACI parametric testing. Mercury removal peaked at 74% using DARCO Hg at a feed rate of 5 lb/MMacf compared to 97% at 3.2 lb/MMacf with DARCO Hg-LH (Figure 6). Mercury removal was 87% using a combination of the KNX and DARCO Hg at a feed rate of 5 lb/MMacf. With the KNX coal additive alone, mercury removal ranged from 57-64% compared to 34% without the additive.

Figure 6 - Meramec ACI Parametric Test Results



Norit DARCO Hg-LH was selected for further evaluation during the 30-day long-term test and was injected at 3.3 lb/MMacf with average mercury removal of 93%. As at Holcomb, no adverse balance-of-plant impacts were observed during the long-term testing and no excess levels of bromine were measured in the flue gas.

Laramie River. Basin Electric's 550 MW Laramie River Plant Unit 3 burns PRB coal and is equipped with a SDA/ESP. Testing was completed first quarter 2005, but results are not yet available.

Monroe. Detroit Edison's 800 MW Monroe Plant Unit 4 burns a blend of PRB and bituminous coal and is equipped with an ESP (258 SCA). Testing began first quarter 2005.

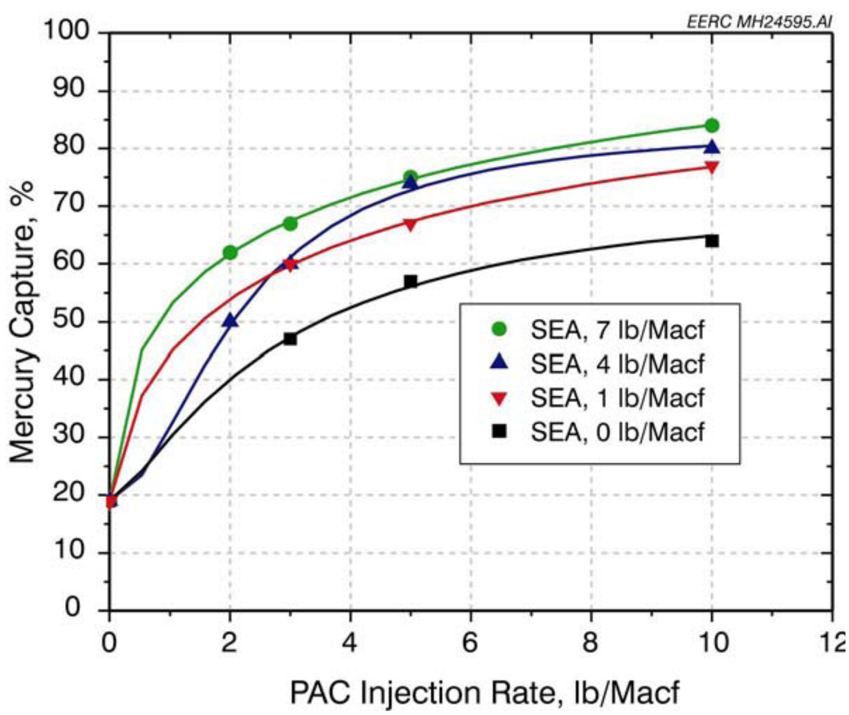
Conesville. American Electric Power's (AEP's) 400 MW Conesville Station Unit 6 burns bituminous coal and is equipped with an ESP (301 SCA) and wet FGD. Testing is scheduled to begin first quarter 2006.

Chemically-Treated PAC and Additives for North Dakota Lignite-Fired Plants

The University of North Dakota Energy & Environmental Research Center (UNDEERC) is testing enhancements to ACI to increase mercury capture for plants burning low-rank North Dakota lignite coals.[15,16,17] Two different technology approaches are being evaluated: (1) injection of chemical additives (generically known as sorbent enhancement additives or SEA) in conjunction with conventional PACs, and (2) injection of chemically-treated PACs. Two SEAs are being evaluated – SEA-1 (calcium chloride) and SEA-2 (a proprietary halogen-based chemical). The two technology approaches will be tested at two plants each, one with an ESP and one with a SDA/FF.

Leland Olds. The first approach was tested at Basin Electric's 220 MW Leland Olds Station Unit 1 that is equipped with an ESP (320 SCA). Testing was completed second quarter 2004. Baseline mercury removal was 15% across the ESP. Average ESP inlet mercury concentration was 7.3 μg/dncm of which 56% was elemental mercury. Figure 7 presents a summary of the parametric test results. At a PAC injection rate of 3 lb/MMacf, mercury removal was ~45% without the SEA-1 and ~65% with an SEA-1 feed rate of 7 lb/MMacf (calcium chloride equivalent to ~500 ppm chlorine in the coal). Average mercury removal was 63% during the one-month long-term testing with a PAC injection rate of 3 lb/MMacf and an SEA-1 feed rate of 7 lb/MMacf.

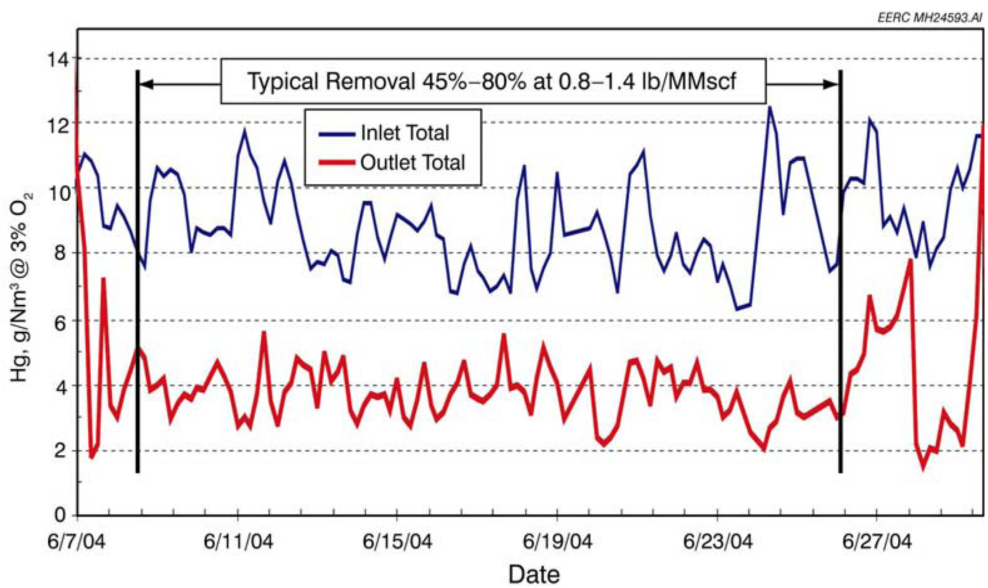
Figure 7 - Leland Olds Unit 1 ACI/SEA Parametric Test Results



Antelope Valley. The first approach is also being tested at Basin Electric's 440 MW Antelope Valley Station Unit 1 that is equipped with a SDA/FF. Testing began second quarter 2005 and includes evaluation of the SEA-2 additive. Test results are not yet available.

Stanton 10. The second approach was tested at Great River Energy's 60 MW Stanton Station Unit 10 that is equipped with a SDA/FF. Testing was completed third quarter 2004. Baseline mercury removal across the SDA/FF was less than 10%. Total vapor-phase mercury concentrations ranged from 7.5-13 µg/dncm at both the SDA inlet and FF outlet with less than 10% oxidized mercury. Five enhanced PACs (iodine, a proprietary chemical, a super activated carbon, and two with bromine) were evaluated during short-term parametric testing and Norit's DARCO Hg was also tested as a benchmark. The DARCO Hg achieved 75% mercury removal at a feed rate of 6 lb/MMacf. However, the two brominated PACs achieved greater than 90% mercury removal at feed rates of only 1.5 lb/MMacf. One of the brominated PACs, DARCO Hg-LH, was selected for use during the one-month long-term testing with mercury removal ranging from 45-80% (60% average) at a PAC injection rate of 0.7 lb/MMacf (Figure 8).

Figure 8 – Stanton Unit 10 ACI Long-Term Test Results

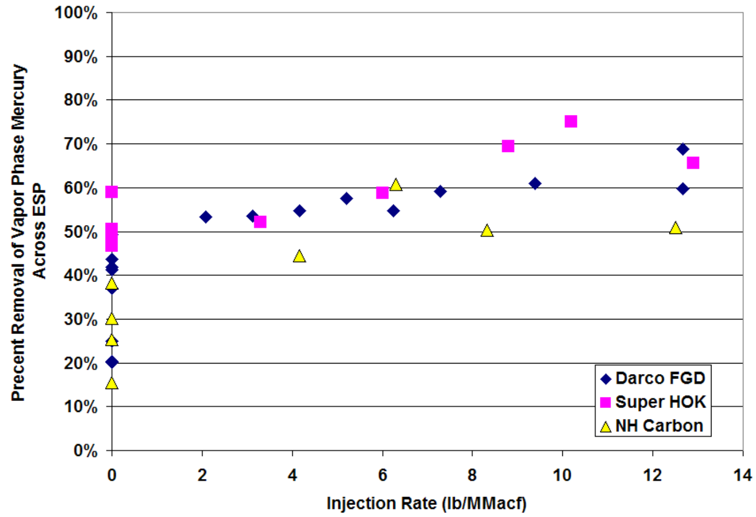


Stanton 1. The second approach is also being tested at Great River Energy's 140 MW Stanton Station Unit 1 that is equipped with an ESP (470 SCA). The Stanton Station has recently switched from North Dakota lignite to PRB coal. Testing is scheduled to begin second quarter 2005 and will be conducted with the unit burning PRB coal.

Sorbent Injection for Low SCA ESP Applications

URS Group, Inc. (URS) conducted an evaluation of ACI upstream of low SCA ESPs.[18,19] Testing was conducted at Southern Company's 100 MW Plant Yates Unit 1 and 2 that burn bituminous coal. Yates Unit 1 is equipped with an ESP (173 SCA) and wet FGD while Yates Unit 2 is equipped with an ESP (144 SCA) that utilizes ammonia and sulfur trioxide flue gas conditioning to improve performance. Testing was completed fourth quarter 2004. Average baseline mercury removal was approximately 35% for both Units 1 and 2. Parametric tests lasting approximately two hours each were conducted on Unit 1 at various feed rates using three PACs (DARCO Hg, RWE Rhinebraun's Super HOK, and Ningxia Huahui's NH Carbon). Performance was similar for the three PACs with maximum mercury removal of approximately 60% across the ESP with PAC injection at 6 lb/MMacf (Figure 9). Similar results were achieved during parametric testing on Unit 2 using only DARCO Hg. There was no significant increase in ESP outlet particulate concentrations during the parametric testing. However, there was an apparent increase in ESP sparking at higher sorbent injection feed rates.

Figure 9 - Yates Unit 1 ACI Parametric Test Results



The Super HOK PAC was selected for use during the one-month long-term testing on Unit 1. Mercury concentrations ranged from 5-13 µg/dncm at the ESP inlet of which 60-75% was oxidized mercury. Baseline mercury removals were 50% across the ESP and a total of 80% across the ESP and wet FGD. PAC injection rates ranged from 4-10 lb/MMacf with mercury removal ranging from 60-85% across the ESP and a total of 70-94% across the ESP and wet FGD. However, it appeared that PAC injection rates above 4.5 lb/MMacf did not significantly improve mercury capture. Approximately 30% of the particulate measurements taken at the ESP outlet exceeded baseline concentrations. However, there was no correlation between the PAC injection rate and the level of ESP outlet particulate concentration. In addition, the wet FGD slurry samples were an unusually dark color (suggesting PAC carryover from the ESP) during a two-week period of the long-term test. Results of the wet FGD slurry analysis are not yet available.

Non-Carbon Based Sorbent

Amended Silicates, LLC (a joint venture of ADA Technologies, Inc. and CH2M Hill) is testing a new non-carbon sorbent, Amended Silicates™, which could provide cost effective mercury capture while avoiding adverse impacts on fly ash sales.[20] Testing will be conducted at Cinergy's 175 MW Miami Fort Station Unit 6 that burns bituminous coal and is equipped with three ESPs in series (190, 163, and 179 SCA). The sorbent will be injected upstream of the first ESP and controlled mercury emissions will be measured downstream of the second ESP. Testing is scheduled to begin first quarter 2006.

Catalysts to Promote Mercury Oxidation Upstream of Wet FGD Systems

URS is conducting pilot-scale testing of fixed-bed honeycomb catalysts at four plants to promote the oxidation of elemental mercury in order to increase overall mercury capture in downstream wet FGD systems.[21,22,23,24] Unlike a NOx SCR catalyst that is located in a high temperature flue gas zone upstream of the air heater, these catalysts would be located in a low temperature zone downstream of the air heater and upstream of the wet FGD system. Four catalyst materials are being tested over a 14-month period at each plant: palladium (Pd #1), titanium/vanadium (SCR), gold, and carbon (Carbon #6). (The four catalysts tested at Coal Creek included a subbituminous ash-based catalyst (SBA #5), which did not perform well and was subsequently replaced with a gold catalyst at the other three plants.)

Coal Creek. Great River Energy's 605 MW Coal Creek Station Unit 1 burns North Dakota lignite coal and is equipped with an ESP and wet FGD. Mercury concentration after the ESP varies from 13-18 µg/dncm, of which approximately 15% is oxidized. Catalyst testing was initiated in October 2002. However, due to fabrication delays, not all of the catalysts were immediately available. Pilot testing for the Pd #1 and SCR catalysts began in October 2002. Testing of the SBA #5 catalyst began in December 2002 and the Carbon #6 catalyst testing began in June 2003. The initial percentage of elemental mercury oxidized by the catalysts ranged from 65-95%, but gradually decreased thereafter. The final catalyst activity measurements were conducted in June 2004. Oxidation of elemental mercury across Pd #1 decreased from 90% to 65% after 20 months in-service and oxidation across Carbon #6 decreased from 95% to 80% after 13 months. However, oxidation activity decreased more rapidly for the SCR and SBA #5 catalysts. After 21 months, oxidation across SCR decreased from 65% to less than 30% and oxidation across SBA #5 decreased from 75% to less than 20% after 18 months. There was some concern that the catalysts might also lead to oxidation of SO_2 and NO that could produce undesirable balance-of-plant effects. However, there was no apparent oxidation of SO_2 to SO_3 and approximately 10 ppmv (7%) oxidation of NO to NO_2.

J. K. Spruce. City Public Service (CPS) of San Antonio's 546 MW J.K. Spruce Plant burns a PRB coal and is equipped with a FF and wet FGD. Testing began in September 2003 and should be completed second quarter 2005. Mercury concentration after the FF varies from 10-13 µg/dncm of which 65-90% is oxidized. This is a relatively high level of oxidized mercury compared to oxidation levels of less than 25% for most plants burning PRB coal. As a result, there has been some difficulty in accurately measuring the elemental mercury concentration due to low values of 1-3 µg/dncm. After approximately one-year in-service, oxidation of elemental mercury across the Pd #1 catalyst was 76%, Carbon #6 was 80%, SCR was 41% and the gold catalyst was 92%.

Monticello. TXU's 750 MW Monticello Station Unit 3 burns Texas lignite and is equipped with an ESP (452 SCA) and wet FGD. Testing began first quarter 2005 and is scheduled to be completed first quarter 2006. Test results are not yet available.

Yates. Southern Company's 100 MW Plant Yates Unit 1 burns low-sulfur bituminous coal and is equipped with an ESP (173 SCA) and wet FGD. Testing scheduled to begin second quarter 2005 and to be completed third quarter 2006.

Chemical Additives to Promote Mercury Oxidation Upstream of Wet FGD Systems

UNDEERC is testing the effectiveness of using chemical additives to increase mercury oxidation and therefore enhance mercury capture at lignite-fired plants equipped with an ESP and wet FGD.[25] Testing is being conducted at two plants:

Milton R. Young. Minnkota Power Cooperative's 450 MW Milton R. Young Unit 2 burns North Dakota lignite and is equipped with an ESP (375 SCA) and wet FGD. Testing began first quarter 2005 and is scheduled to be completed second quarter 2005.

Monticello. TXU's 750 MW Monticello Unit 3 burns Texas lignite and is equipped with an ESP (452 SCA) and wet FGD. Testing is scheduled to begin third quarter 2005.

MerCAP - A Different Approach

URS is testing EPRI's Mercury Control via Adsorption Process (MerCAP™) technology.[26,27] The process involves placing a regenerable, fixed-structure gold sorbent into the flue gas stream to capture mercury. Testing is being conducted at two plants:

Stanton. Great River Energy's 60 MW Stanton Station Unit 10 previously burned North Dakota lignite, but switched to PRB after the testing had begun. The unit is equipped with a SDA/FF. The MerCAP sorbent structures are retrofitted into a single compartment of the fabric filter baghouse equivalent to a 6 MW demonstration. Testing began third quarter 2004 and is scheduled to be completed second quarter 2005. Baseline mercury capture was less than 10% across the SDA/FF with mercury concentration at the FF outlet ranging from 6-12 µg/dncm and was typically greater than 95% elemental mercury. Three configurations of MerCAP plates are being evaluated: 1) acid-treated gold plates with 1" spacing; 2) untreated gold plates with 1" spacing; and 3) untreated gold plates with ½" spacing. Table 4 presents a summary of results available to date. The acid-treated plates have shown the best performance with an average mercury removal of 30-35%. Regeneration of the MerCAP plates was attempted, but showed only a modest improvement (5-15%) in performance.

Table 4 – Stanton Unit 10 MerCAP Preliminary Test Results

Substrate	Plate Spacing	Installation Date	Hours in Service	Average Mercury Removal
Acid-treated	1"	8/22/04	3,123	30-35%
Untreated	1"	11/18/04	1,035	15-18%
Untreated	½"	11/18/04	1,035	25-30%
Baseline	N/A	N/A	N/A	0%

Yates. Southern Company's 100 MW Plant Yates Unit 1 burns low-sulfur bituminous coal and is equipped with an ESP (173 SCA) and wet FGD. The MerCAP sorbent structures are configured as a mist eliminator located downstream of a 1 MW pilot-scale wet FGD absorber. Testing is scheduled to begin second quarter 2005 and is scheduled to be completed fourth quarter 2005.

PHASE II, ROUND 2 FIELD TESTING (2005-07)

Brominated Sorbents for Low SCA Cold-Side and Hot-Side ESPs

Sorbent Technologies will conduct additional testing of brominated-PACs at three plants: (1) Midwest Generation's 216 MW Crawford Station Unit 7 that burns subbituminous coal and is equipped with an ESP (112 SCA); (2) Progress Energy's 75 MW Lee Station Unit 1 that burns bituminous coal and is equipped with an ESP (300 SCA); and (3) Midwest Generation's 262

MW Will County Station Unit 3 that burns subbituminous coal and is equipped with a hot-side ESP (173 SCA). In addition to their standard brominated-PAC, B-PAC™, Sorbent Technologies will also evaluate a modified formulation for hot-side ESP applications, H-PAC™, and a formulation that enables continued fly ash use in concrete, C-PAC™. Initial testing is scheduled to begin third quarter 2005 at the Lee Station.

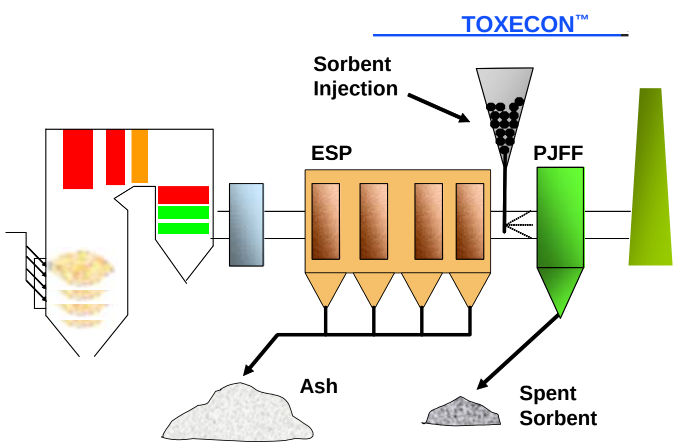
Mer-Cure – A New Proprietary PAC

ALSTOM Power will evaluate a proprietary chemically-treated activated carbon sorbent injection process – Mer-Cure™ - that promotes oxidation and capture of mercury across an ESP. Testing will be conducted at three plants burning different coals: (1) PacificCorp's Dave Johnston Plant Unit 3 that burn PRB coal and is equipped with an ESP (~600 SCA); (2) Basin Electric's 220 MW Leland Olds Station Unit 1 that burns North Dakota lignite and is equipped with an ESP (320 SCA); and (3) Reliant Energy's Portland Station Unit 1 that burns bituminous coal and is equipped with an ESP (284 SCA). Initial testing is scheduled to begin third quarter 2005 at the Dave Johnston Plant.

TOXECON for Texas Lignite-Fired Plants

UNDEERC will evaluate the long-term feasibility of using ACI to reduce mercury emissions at TXU Energy's Big Brown Steam Electric Station that typically burns a 70% Texas lignite with 30% subbituminous coal blend and occasionally 100% Texas lignite. The two 600 MW units at Big Brown are equipped with an ESP (162 SCA) and a downstream PJFF in a COHPAC configuration. The project will test several PACs and SEAs to cost-effectively remove mercury from lignite combustion gases using EPRI's toxic emission control (TOXECON™) process (Figure 10). TOXECON is a process in which PAC is injected downstream of the primary particulate control device and upstream of a pulse-jet baghouse. The TOXECON configuration allows for separate treatment or disposal of the ash collected in the primary particulate control device. Initial testing is scheduled to begin first quarter 2006.

Figure 10 - EPRI's TOXECON Process Configuration

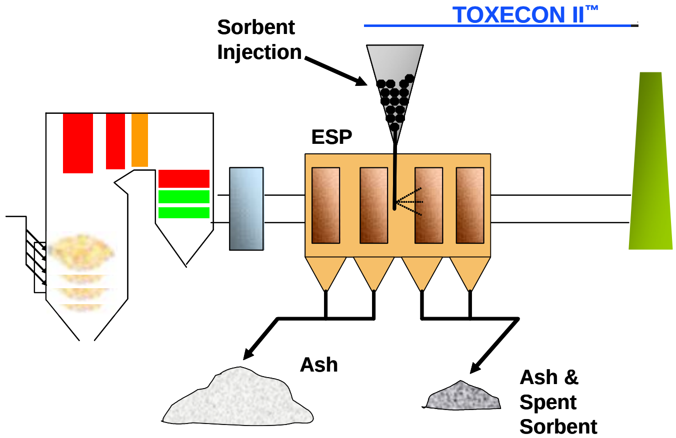


Low-Cost Options for Moderate Levels of Mercury Control

ADA-ES will test two new mercury control technologies for plants equipped with ESPs: TOXECON II™ for cold-side ESPs and proprietary sorbents for hot-side ESPs. The TOXECON II technology injects a sorbent directly into the downstream collecting fields of a cold-side ESP

(Figure 11). The majority of the fly ash is collected in the upstream collecting fields, resulting in only a small portion of carbon-contaminated ash.

Figure 11 - EPRI's TOXECON II Process Configuration



The TOXECON II technology will be tested at AEP's 1300 MW Gavin Station Unit 1 or 2 (430 SCA) that burn bituminous coal and Entergy's 835 MW Independence Station Unit 1 (542 SCA) that burns PRB coal. The proprietary sorbents for hot-side ESPs will be tested at MidAmerican's 80 MW Council Bluffs Energy Center Unit 2 (224 SCA) and MidAmerican's 740 MW Louisa Station Unit 1 (459 SCA), both of which burn PRB coal. Initial testing is scheduled to begin third quarter 2005 at the Independence Station.

Chemical Additive for Prevention of Mercury Re-Emission from Wet FGD

URS will demonstrate the use of an additive in wet lime or limestone FGD systems. The additive is designed to prevent oxidized mercury from being reduced and subsequently re-emitted from the FGD absorber as elemental mercury. Testing will be conducted at three plants: (1) TXU's 750 MW Monticello Station Unit 3 that burns Texas lignite coal and is equipped with an ESP (452 SCA); (2) Southern Company's 100 MW Plant Yates Unit 1 that burns low-sulfur bituminous coal and is equipped with an ESP (173 SCA) and wet FGD; and (3) AEP's 400 MW Conesville Station Unit 5 or 6 that burn high-sulfur bituminous coal and are equipped with an ESP (301 SCA) and wet FGD. Testing is scheduled to begin second quarter 2005 at the Monticello Station.

Combustion Modifications for Mercury Control

GE Energy's Energy & Environmental Research Corporation (GE EERC) has developed a new, cost-effective technology that combines mercury removal with NOx emission control. GE EERC will conduct a field demonstration of its technology at Progress Energy's 250 MW Lee Unit 3 that burns a bituminous coal and is equipped with an ESP (~300 SCA). The objective of the demonstration is to demonstrate at least 90 percent mercury removal. Initial testing is scheduled to begin third quarter 2005.

COMMERCIAL DEMONSTRATION

In addition to field testing mercury control technologies, DOE/NETL is also funding a $53 million commercial demonstration of EPRI's TOXECON process through the Clean Coal Power Initiative (CCPI). This first-of-a-kind commercial demonstration of TOXECON will be implemented at We Energies' Presque Isle Power Plant located in Marquette, Michigan. Presque Isle burns PRB subbituminous coal, and the TOXECON process will be installed to treat the combined flue gas stream of Units 7, 8, and 9, which total 270 MW. The project was initiated in 2003 and construction is scheduled for completion in December 2005. Extended long-term testing of the process will begin in January 2006 and be completed in December 2008.

SUMMARY

The DOE/NETL mercury control technology research program has helped to advance the understanding of the formation, distribution, and capture of mercury from coal-fired power plants. Some general observations can be drawn from the results of mercury control technology field testing that has been carried out to date:

1. Coal properties, such as chlorine content, can impact the potential mercury capture performance of mercury control technologies.
2. Significant variability in baseline mercury capture of existing APCDs has been observed at similar units as well as at individual units tested at different times.
3. Mercury capture with ACI has been demonstrated in short-term and long-term full-scale field testing. However, the range of effectiveness depends on coal type and plant APCD configuration. More long-term evaluation is necessary to determine realistic cost and performance estimates for various plant arrangements.
4. For all of the mercury control technologies, uncertainties remain regarding the capture effectiveness with various coal-rank and existing APCD configurations, balance-of-plant impacts, and by-product use and disposal. For example, there is the potential for activated carbon carryover for low SCA ESPs.
5. Baseline mercury capture performance for lignite and PRB coal-fired plants with an ESP or SDA/FF is relatively low and untreated activated carbon injection performance is limited. This testing demonstrated that mercury capture may be enhanced through addition of halogens via coal blending, coal additives, or use of chemically-treated activated carbon.

While our knowledge of the formation, distribution, and capture of mercury from coal-fired power plants has greatly advanced over the past decade, many uncertainties and challenges remain. Moreover, the technology to effectively remove mercury from the diverse population of coal-fired plants currently in operation is not yet commercially available. Therefore, as U.S. coal-fired power plant operators begin to formulate plans for compliance with Phase II of EPA's CAMR, it is critical that RD&D continues to address these challenges.

In response, DOE/NETL is continuing to partner with industry and other key stakeholders in carrying out a comprehensive mercury control technology RD&D program. This effort is being carried out through both extramural and in-house research focused on (1) enhancing the capture of mercury across existing APCDs, and (2) developing novel stand-alone control concepts to achieve high levels of mercury removal at costs considerably lower than current technology. For more information, visit the Web site: *http://www.netl.doe.gov/coal/E&WR/index.htm*.

ACKNOWLEDGMENTS
The authors acknowledge the contribution of colleagues Bruce Lani, William Aljoe, Dawn Chapman, Charles Miller, Sara Pletcher, Peter Botros, and Lindsay Green.

DISCLAIMER
Reference in this article to any specific commercial product or service is to facilitate understanding and does not imply endorsement by the U.S. Department of Energy.

About the Authors
Thomas J. Feeley, III is a technology manager for the U.S. Department of Energy, National Energy Technology Laboratory in Pittsburgh, PA. He can be reached at Thomas.Feeley@netl.doe.gov. **Lynn A. Brickett** is a project manager for the U.S. Department of Energy, National Energy Technology Laboratory in Pittsburgh, PA. **B. Andrew O'Palko** is a project manager for the U.S. Department of Energy, National Energy Technology Laboratory in Morgantown, WV. **James T. Murphy** is a senior environmental engineer for Science Applications International Corp. in Pittsburgh, PA.

REFERENCES

[1] See http://www.epa.gov/ttn/atw/utility/utiltoxpg.html
[2] Kilgroe, J.; Sedman, C.; Srivastava, R.; Ryan, J.; Lee, C.; Thorneloe, S. *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-21-02*; EPA-600/R-01-109; U.S. Environmental Protection Agency, April 2002.
[3] Laudal, D.L.; Thompson, J.S.; Pavlish, J.H.; Brickett, L.; Chu, P.; Srivastava, R.K.; Lee, C.W.; Kilgroe, J. The Evaluation of Mercury Speciation at Power Plants Using SCR and SNCR Control Technologies; *EM* 2003, *February*, 16-22.
[4] Feeley, T.J.; Murphy, J.T.; Hoffmann, J.W.; Granite, E.J.; and Renninger, S.A. DOE/NETL's Mercury Control Technology Research Program for Coal-Fired Power Plants; *EM* **2003**, *October*, 16-23.
[5] Bustard, J.; Durham, M.; Lindsey, C.; Starns, T.; Baldrey, K.; Martin, C.; Schlager, R.; Sjostrom, S.; Slye, R.; Monroe, L.; Miller, R.; Chang, R. *Full-Scale Evaluation of Mercury Control with Sorbent Injection and COHPAC at Alabama Power E.C. Gaston*. Presented at the A&WMA Specialty Conference on Mercury Emissions: Fate, Effects, and Control and the EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: Mega Symposium, Chicago, IL, August 2001.
[6] Bustard, J.; Durham, M.; Starns, T.; Lindsey, C.; Martin, C.; Schlager, R.; Baldrey, K. *Full-Scale Evaluation of Sorbent Injection for Mercury Control on Coal-Fired Power Plants*. Presented at Air Quality III: Mercury, Trace Elements, and Particulate Matter Conference, Arlington, VA, September 9–12, 2002.
[7] Bustard, J.; Renninger, S.; Chang, R; Miller, R.; Monroe, L.; Sjostrom, S. *Results of Activated Carbon Injection for Mercury Control Upstream of a COHPAC Fabric Filter*. Presented at the A&WMA/ EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19–22, 2003.
[8] Starns, T.; Bustard, J.; Durham, M.; Martin, C.; Schlager, R.; Sjostrom, S.; Lindsey, C.; Donnelly, B.; Alfonso, R.; Chang, R.; Renninger, S. *Results of Activated Carbon Injection*

Upstream of Electrostatic Precipitators for Mercury Control. Presented at the A&WMA/ EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19–22, 2003.

[9] Berry, M. et al. *Field Test Program for Lon-Term Operation of a COHPAC System for Removing Mercury from Coal-Fired Flue Gas.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[10] Nolan, P.; Redinger, K.; Amrhein, G.; Kudlac, G. Mercury Emissions Control in Wet FGD Systems. In *Proceedings of Air Quality III: Mercury, Trace Elements, and Particulate Matter Conference, Arlington, VA, September 9–12, 2002.*

[11] McCoy, M. et al. *Full-Scale Mercury Sorbent Injection Testing at DTE Energy's St. Clair Station.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[12] Nelson, S. et al. *Accumulated Power Plant Mercury Removal Experience with Brominated PAC Injection.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[13] Sjostrom, S. et al. *Full-Scale Evaluation of Mercury Control by Injecting Activated Carbon Upstream of a Spray Dryer and Fabric Filter.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[14] *Evaluation of Sorbent Injection for Mercury Control;* Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-03NT41986; ADA-ES, Inc., February 2, 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[15] Machalek, T. et al. *Full-Scale Activated Carbon Injection for Mercury Control in Flue Gas Derived from North Dakota Lignite.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[16] Thompson, J. et al. *Enhancing Carbon Reactivity for Mercury Control: Field Test Results from Leland Olds.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[17] *Enhancing Carbon Reactivity in Mercury Control in Lignite-Fired Systems.* Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-03NT41989; Energy & Environmental Research Center, University of North Dakota, February 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[18] Dombrowski, K. et al. *Sorbent Injection for Mercury Control Upstream of Small-SCA ESPs.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[19] *Sorbent Injection for Small ESP Mercury Control in Low Sulfur Eastern Bituminous Coal Flue Gas*; Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-03NT41987; URS Group, Inc., January 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[20] Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-04NT41988; Amended Silicates, LLC, October 15, 2004. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[21] Blythe, G. et al. *Pilot Testing of Oxidation Catalysts for Enhanced Mercury Control by Wet FGD.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, May 19-22, 2003.

[22] Blythe, G. et al. *Pilot Testing of Oxidation Catalysts for Enhanced Mercury Control by Wet FGD.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[23] *Pilot Testing of Mercury Oxidation Catalysts for Upstream of Wet FGD Systems.* Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-01NT41185; URS Corporation, January 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[24] *Pilot Testing of Mercury Oxidation Catalysts for Upstream of Wet FGD Systems.* Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-04NT41992; URS Corporation, January 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[25] *Large-Scale Mercury Control Technology Testing for Lignite-Fired Utilities – Oxidation Systems for Wet FGD.* Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-03NT41991; Energy & Environmental Research Center, University of North Dakota, November 2004. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

[26] Ebner, T. et al. *Large Scale Demonstration of the MerCAP™ Technology for Mercury Control.* Presented at the A&WMA/EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Mega Symposium, Washington, DC, August 30-September 2, 2004.

[27] *Evaluation of MerCAP™ for Power Plant Mercury Control.* Quarterly Technical Report to the U.S. Department of Energy under Cooperative Agreement No. DE-FC26-03NT41993; URS Group, Inc., January 2005. See http://www.netl.doe.gov/coal/E&WR/mercury/index.html

Utilities split on readiness of IGCC

For some gencos, the dearth of operating experience for integrated gasification combined-cycle plants adds too much uncertainty to the risk/reward equation for new-capacity technology options. For others, the possibility of being able to comply with air pollution limits as far out as 2018, as well as to meet all-but-certain CO_2 caps, makes IGCC well worth investing in—now.

By John Javetski

Resource planners at electric utilities have never had it so good—or bad. On the one hand, planners have never had more technology options for building needed generating capacity at their disposal. On the other are the huge cost and reliability uncertainties inherent in the deployment of any new and unproven power production technology—represented all too well by integrated gasification combined-cycle (IGCC) plants.

This article represents a bit of a departure from POWER's normal modus operandi. It attempts to cut through the considerable hype that has accompanied IGCC technology for the past few years by not assuming (as many articles do) that utilities leap at any chance, whatever the risks, to be among the first to employ a sexy new technology.

Rather than survey the field of candidate IGCC technologies (which would be appropriate if IGCC had no apparent downsides), this article begins where utility resource planners begin: by comparing the highest-level technical and economic characteristics of IGCC with those of its closest-competing generation technology—conventional pulverized coal (PC) combustion. IGCC is still in its infancy, and there will be plenty of opportunities for POWER to cover its evolution as thoroughly as the magazine has reported on other paradigm shifts in generating technology over the past 125 years.

Of cost and carbon

Perhaps the biggest question involving IGCC plants is whether their presumed ability to be equipped inexpensively in the future to capture CO_2 justifies IGCC's capital cost premium over mainstream PC combustion. Conventional wisdom puts that premium at 15% to 20%. Table 1 compares IGCC's estimated costs with those of other generating technologies.

The biggest question involving IGCC plants is whether their presumed ability to be equipped inexpensively in the future to capture CO_2 justifies IGCC's capital cost premium.

At the Platts Second Annual IGCC Symposium in Pittsburgh this May, the hopes and hurdles for adoption of the technology were on full display, and cost figured prominently in the presentations of utilities on both sides of the divide.

Kay Pashos, president of Duke Energy Indiana, ticked off five factors that have driven her company to seriously consider building a 600-MW IGCC plant in southern Indiana in the near future. Two—the abundance of Midwest coal reserves and the rising price of natural gas—are so clear that they require no further discussion here. Pashos' third factor—IGCC's superior and more-cost effective environmental performance on high-sulfur local coals, relative to PC combustion—is inextricably intertwined with the fourth and fifth factors: shrinking pollutant emissions limits and the availability of incentives to close IGCC's capital cost gap.

The trend of pollutant emissions limits that seem to be marching toward zero began with the 1990 Clean Air Act Amendments, continued with the NO_x SIP (state implementation plan) Call program, and remains ongoing in the form of the Clean Air Interstate and Mercury Rules (CAIR and CAMR). Under CAIR and CAMR, compliance deadlines for utility emissions of NO_x, SO_2, and mercury are already in place as far out as 2018.

It is also possible that CO_2 will be classified as a pollutant, making it subject to

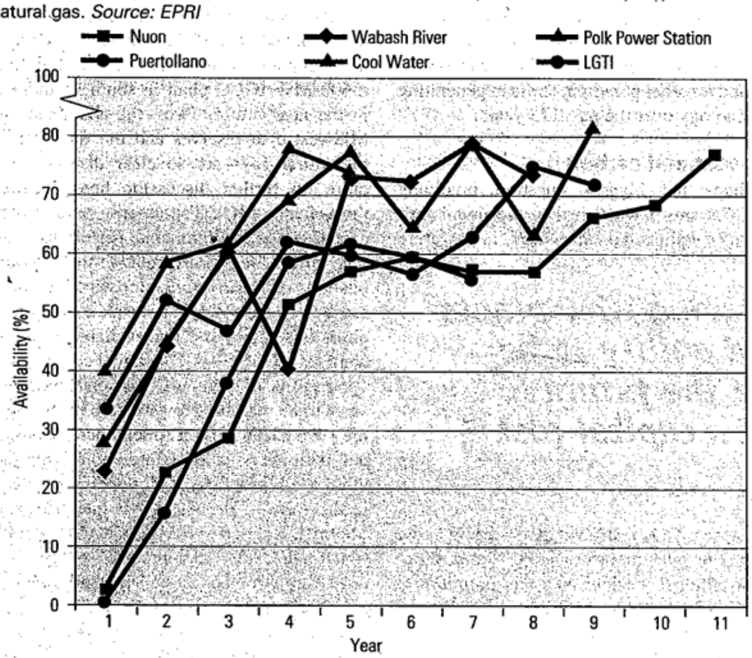
Table 1. Comparing the costs of IGCC and other generating technologies. *Source: Pace Global Energy Services*

	Cost of generation ($/MWh)						
	Hydro	Gas turbine combined cycle	Simple-cycle combustion turbine	Nuclear	Pulverized coal firing	Fluidized bed	Integrated gasification combined cycle
Fuel	0	35	53	3	14	15	14
Capital	24	10	6	30	24	26	31
Variable O&M	0	2	1	1	2	2	4
Fixed O&M	3	3	2	6	4	5	7
Emissions (SO_2, NO_x)	0	2	2	0	8	4	2
Total cost of generation	**27**	**52**	**64**	**40**	**52**	**52**	**58**

Table 2. Commercial-scale coal/petcoke-based IGCC demonstration plants. *Source: Ola Maurstad, Massachusetts Institute of Technology's Laboratory for Energy and the Environment*

Project operator/ Plant name	Location	Electric output (net)	Gasifier type (current owner)	Gas turbine	Dates of operation
Southern California Edison/Cool Water	Barstow, Calif.	100 MW	GE (with heat recovery)	GE 7E	1984–1988
Dow Chemical (Destec)/Louisiana Gasification Technology Inc. (LGTI)	Plaquemine, La.	160 MW	ConocoPhillips E-gas	Siemens SGT6-3000E	1987–1995
Nuon/Nuon Power Buggenum	Buggenum, The Netherlands	253 MW	Shell	Siemens SGT5-2000E	1994–present
Destec, PSI Energy/Wabash River	West Terre Haute, Ind.	262 MW	ConocoPhillips E-gas	GE 7FA	1995–present
Tampa Electric Co. (TECO)/ Polk Power Station	Mulberry, Fla.	250 MW	GE (with heat recovery)	GE 7FA	1996–present
Elcogas/Puertollano	Puertollano, Spain	298 MW	Prenflo	Siemens SGT5-4000F	1998–present
Sierra Pacific Power Co./Pinon Pine	Reno, Nev.	99 MW	KRW air-blown fluidized bed	GE 6FA	1998–2000 (18 start-up attempts, failed to achieve steady-state operation)

Good enough for baseload? The availability histories of the six successful IGCC demonstration plants show that most were able to reach the 70% to 80% range (excluding operation on back-up fuel), but only after at least five years of operation. Equipped with a spare gasifier, an IGCC plant may be able to match the availability of a combined-cycle plant burning natural gas. *Source: EPRI*



regulation by the U.S. EPA. Two states already cap CO_2 emissions from power plants, and others are sure to follow now that global warming has become a cultural touchstone.

Regarding the availability of incentives to help utilities close IGCC's aforementioned capital cost gap, Pashos noted that Indiana law provides for timely recovery of an IGCC plant's construction and operating costs, as well as substantial investment tax credits—10% of the first $500 million of a project's cost, plus 5% of the remainder.

In addition to those sops, the 2005 Energy Policy Act (EPAct) provides a 20% investment tax credit for "eligible properties" for gasification. That wording, however, may effectively reduce the actual credit for an IGCC plant to 12%. Because the combined-cycle power plant portion of an IGCC facility accounts for as much as 40% of its overall cost, if the tax credit is applied only to the cost of the gasifier, a utility may only be able to obtain a credit amounting to 20% of 60% of the facility's cost, or 12%. In other words, the gasification may be covered, but the integration may not be. What's more, there's a cap on the total federal tax credit available each year, and at press time the DOE has already received applications for credits totaling four times that level (see p. 4).

Adventures in availability

That Duke Energy Indiana is considering building an IGCC plant (according to Pashos, a go/no-go decision will be made by the middle of 2007) underscores the utility-specific nature of the technology's pros and cons. As PSI Energy, Duke Energy Indiana's parent—Cinergy Corp.—partnered with Destec to build Wabash River, one of the seven demonstration IGCC plants that account for the technology's entire operating history worldwide (Table 2).

The Wabash River plant went commercial in late 1995. Within a few months, both the gasification and combined-cycle plants were running at full capacity and in environmental compliance on high-sulfur Illinois Basin bituminous coal. However, by the end of the first year of operation, annual availability measured just 35%. More than half of total outage time was attributed to failures of the ceramic candle filters in the gasification plant's dry char particulate removal system.

After changing to metallic filters and making other improvements, Wabash River saw its production and availability numbers rise during its second and third years. During the third year, the plant successfully demonstrated the ability to use a second coal feedstock as well as a blend of two different Illinois No. 6 coals, improving the site's fuel flexibility. Later, up to 2,000 tons/day of petroleum coke were gasified and converted to more than 250 MW of power without exceeding permitted emissions levels.

In 1998 the Wabash River plant passed the milestones of 10,000 hours of operation on coal and 1,000,000 tons of coal processed. Net availability during that year was calculated at 77% by excluding the downtime of the power plant and subtracting time spent testing alternative fuels. Since 2000, the

Going forward

In a paper presented at ELECTRIC POWER 2006, Dave Stopek of Sargent & Lundy laid out the challenges facing utilities that have concluded IGCC is indeed the path forward. The next thing they must do, he said, is answer the following questions for a proposed plant of a given capacity (for example, 600 MW): What is the plant's likely cost? and How do I select a technology supplier?

Plant cost

The first step in the cost estimation process is to choose a fuel and a site for the facility. IGCC plant design is very sensitive to fuel characteristics such as heating value and sulfur, ash, and moisture content. This sensitivity often makes it impossible to maximize the plant's fuel flexibility. As a compromise, gencos often opt to design for a "blend" of fuels such as petroleum coke and Powder River Basin (PRB) coal. They then assume that an Illinois coal will fall someplace in the middle of the fuel range.

Solutions such as these are possible, but increasing a plant's fuel flexibility increases its capital cost. Variables include the desired range of operating capacity, sulfur level, and the need for a coal-handling facility capable of dealing with multiple fuels.

Estimating the cost of an IGCC plant is complicated by the fact that very few of them have been built. Cost data on gasification facilities are limited to technology developers. In general, cost estimates and design comparisons for conventional coal-fired plants are based on well-defined numbers, whereas those for IGCC plants must be made on a case-by-case basis.

So how does one develop a cost estimate for budgeting purposes? All existing IGCC plants were developed by putting several technologies together and negotiating license agreements with individual suppliers to piece together the system. Only then could the plant design process begin, around each subsystem technology. This process has been simplified by the formation of the three major IGCC alliances.

In the past, when a utility wanted a budget estimate, it could rely on getting a reasonable number from a technology vendor. However, because of the growing interest in and site-specific nature of each IGCC design, vendors have become reluctant to offer much in the way of information to speculative clients. Rumor has it that some have asked clients for several hundred thousand dollars to do a conceptual study.

To develop data sufficient for firm construction budgeting and financing, a front-end engineering design (FEED) package is needed. This represents about 10% of vendor engineering and can cost in the range of \$4 million to \$6 million. The results of the FEED package provide sufficient information for an engineering/procurement/construction (EPC) contractor to develop a bid package.

As an alternative vehicle for simple budget development, many companies have relied on published studies. However, published studies have limitations:

- Most consider nth plant design.
- Many consider technologies that are not yet commercially available for IGCC (two examples are the H-technology turbine and advanced, membrane-based oxygen systems).
- Many studies assume a high level of integration that may not be advisable for an early deployment.
- Many do not provide complete details of all assumed contingencies or how the owner's costs (balance-of-plant equipment, permitting, switchyard, EPC contractor's risk premium, etc.) will be allocated.

These limitations have caused substantial confusion among utility planning staffs, regulators, environmental activists, and EPC firms trying to establish realistic estimates without detailed input from IGCC technology suppliers.

Selecting a supplier

Selecting a technology supplier is not nearly as simple for IGCC as it is for pulverized coal (PC) technology. With PC technology, vendors provide bids against a specification. Differences between bids are analyzed in a straightforward manner, leading to determination of the most cost-effective technology or technologies.

In the current IGCC environment, suppliers do not respond to a solicitation with a firm price offer. This forces the prospective utility customer to decide which supplier offers the "best" overall package of technology, assurances, financing assistance, equipment scope of supply, and overall guarantees. Only then can the customer begin negotiating the prices of a scoping study and a FEED package. Following the negotiations, the utility must negotiate a final cost and strive to stay within that budget. Here, true comparison "shopping" would require buying multiple, costly FEED packages. Sargent & Lundy knows of no utility that has pursued this approach.

Selecting a technology supplier via this method would require sorting through the technical differences associated with adoption of competing technologies, including:

- Relative heat rate and emissions performance firing different fuels.
- The impacts of fuel feed system on design (slurry vs. dry).
- Options for syngas cleanup systems.
- The degree of thermal integration preferred by the supplier.
- The turbine supplier's experience with syngas.
- Ways to integrate CO_2 capture in the future.

Obviously, this is a daunting task that calls for seeking assistance from a reputable EPC contractor.

In summary, the decision to proceed with IGCC will not likely be made purely on the basis of cost, at least not in the near term. Other factors must be weighted heavily in the decision matrix. Ultimately, utilities must choose either to participate in the development of IGCC technology or wait at least five years to benefit from the operating experience of plants that have yet to be built. With billions of dollars at stake, this decision cannot be taken lightly by companies responsible for both maintaining their financial health and supplying reliable, affordable electricity to consumers.

Table 3. Syngas production technology suppliers. *Source: Worley Parsons*

Design feature	GE Energy (formerly Texaco)	ConocoPhillips E-Gas	Shell
Feed system	Coal in water slurry	Coal in water slurry	Dry coal; lock hopper and pneumatic conveying
Gasifier configuration	Single-stage downflow	Two stage upflow	Single-stage upflow
Gasifier wall	Refractory	Refractory	Membrane
Pressure (psig)	500–1,000	Up to 600	Up to 600
Notes	Quench or with heat recovery	Heat recovery	Heat recovery

Table 4. Which is cleaner: IGCC or PC? *Source: U.S. EPA*

	IGCC bituminous	Subcritical PC bituminous	Subcritical PC subbituminous	Subcritical PC lignite
NO_x	0.048	0.06	0.06	0.06
SO_2	0.043 (99% removal)	0.086 (98% removal)	0.065 (87% removal)	0.04 (98% removal)
PM/PM_{10}	0.007	0.012	0.012	0.012
Volatile organic compounds	0.0017	0.0024	0.0027	0.0027
CO	0.03	0.10	0.10	0.10
Mercury	0.76×10^{-6}	0.76×10^{-6}	0.42×10^{-6}	0.73×10^{-6}

Notes: IGCC = integrated gasification combined cycle; PC = pulverized coal. All values are in lb/mmBtu. IGCC NO_x value is based on 15 ppmvd concentration @15% excess O_2, without selective catalytic reduction. The 87% SO_2 removal rate cited for subcritical PC subbituminous assumes the coal has a very low sulfur content (0.22%).

plant has operated with minimal problems and significantly improved on-stream performance while meeting all of its environmental targets. Today, Cinergy continues to dispatch Wabash River at a heat rate of 8,900 Btu/kWh (HHV), although the plant is now owned and operated by Global Energy Inc.

Wabash River's increasing availability over the years as it got its sea legs may seem impressive. However, the plant is only in the middle of the "gang of six" IGCC demo plants in terms of availability (see figure, p. 56). The inability of any plant to reach and maintain 80% availability doesn't sit well with Marty Smith, manager of environmental policy for Xcel Energy. Speaking at the Platts IGCC Symposium, Smith said that an IGCC plant would have to be capable of 90% availability to warrant his serious consideration.

In fact, the availabilities demonstrated by the four currently operating IGCC plants (Nuon Power Buggenum and Puertollano in Europe, and Wabash River and Polk Power Station in the U.S.) mean little to Smith because "[they] don't represent the technology that would be built today." He also lamented:

- The lack of standardization among the four IGCC technology candidates currently on the market (Table 3).
- The "vexing" nature of the technology's costs.
- The performance penalty incurred when low-rank fuels such as lignite and Powder River Basin (PRB) coal are gasified. Western coals are higher in ash and moisture content and have other characteristics that make them much harder for a gasifier to handle.
- The industry's minimal experience with CO_2 capture and running a gas turbine on a hydrogen-rich fuel. As a practical matter, future IGCC plants will capture so much carbon dioxide so quickly that storing it on-site will be impossible. The gas will have to be piped away in real time for sale or sequestration. Although carbon sequestration is being demonstrated successfully at a number of sites worldwide, the underground geologic formations suitable for the process aren't necessarily available where IGCC plants will likely be built—close to coal mines.

Financing IGCC

At the Platts Second Annual Coal-fired Generation Conference about a year ago in Chicago, there was no shortage of financiers skeptical about the prospects for funding IGCC projects.

"As a firm, we are generally bullish [on IGCC]. Personally, I'm less optimistic," said John Cogan, senior VP for global energy investment banking at Credit Suisse First Boston LLC. A company such as American Electric Power or Cinergy will have to build an IGCC plant and put it into commercial service to determine how much it really costs to build, he said.

"IGCC makes a lot of sense, but at the end of the day it comes down to costs," said Joseph Esteves, managing director of LS Power Development LLC. LS Power is developing a 1,600-MW pulverized coal–fired project in Arkansas. "If we have trouble selling the output of a PC plant," it would be even harder to sell the output from an IGCC plant, said Esteves. Because an IGCC plant is more expensive to build than a PC plant, the cost of electricity to the customer is likely to be higher.

LS Power has lined up significant commitments for its Plum Point plant in Arkansas, but it has been tough going, said Esteves. He added that LS Power is taking a "novel" approach to financing its project. "We're not going to wait to get the final piece of the Arkansas project's capacity sold before closing on the financing."

Esteves said bankers he has polled typically want to see a five-year track record for a particular technology before they commit to financing, and that does not yet exist for IGCC. What banks want to see, he explained, is a smoothly functioning plant that was built under a tight construction schedule. "Project finance is not designed for new technology," he said. "[And] I don't see any independents [successfully] building an IGCC [plant]," said Esteves, "It will have to be put into ratebase by a utility" or built with some form of government subsidy, he said.

Nonetheless, several independents have proposed IGCC plants. In fact, some of them came to IGCC because of the difficulties they had securing permits for PC plants. They are now seeking permits for IGCC plants and trying to line up financing. It is a difficult process.

Although the cleaner emissions profile of an IGCC plant relative to PC plants has attracted developers to the technology, it is not always such an easy sell. As Table 4 shows, IGCC technology is a clear winner over subcritical PC technology only in terms of emissions of SO_2, particulate matter (PM), and carbon monoxide. Both are fairly close in production of NO_x and removal of volatile organic compounds (VOCs).

IGCC plants, however, enjoy a big advantage when it comes to mercury and carbon dioxide control. IGCC plants should be able to remove 90% of mercury at 1/10th the cost of processes used by conventional plants. They also should be easier and less expensive to retrofit for CO_2 capture (see p. 60) because at an IGCC plant carbon dioxide constitutes 90% of flue gas, vs. 10% at a conventional PC plant. It will be collected by water-gas shift reactors added to the syngas treatment system as well as by physical absorption processes. ■